Rate Review and Customer Outreach Program Evaluation of Arizona Public Service Company

Docket No. E-01345A-19-0003

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Submitted to:
The Arizona Corporation Commission
by the Utilities Division Staff
In Conjunction with:

Overland Consulting
11551 Ash Street, Suite 215
Leawood, Kansas 66211
(913) 599-3323

1. INTRODUCTION AND EXECUTIVE SUMMARY

BACKGROUND AND PROJECT SCOPE

On January 9, 2019, the Arizona Corporation Commission ("Commission"), consistent with the letter filed by Chairman Burns and Commissioner Dunn on December 24, 2018, directed Staff to initiate a rate review of Arizona Public Service Company ("APS" or "Company") to evaluate the effectiveness of the APS Customer Education and Outreach Program ("CEOP"), and to evaluate the possibility that APS may be over earning. Further, the Commission directed Staff to hire a consultant to assist with the rate review. It was understood that this Report would not result in an adjustment to the rates approved in Decision No. 76295.

On February 11, 2019, the Utilities Division Staff ("Staff") issued a Request for Proposal ("RFP") related to the APS rate review to 147 consulting companies. The RFP was also posted to the Commission's website. On February 25, Staff received two RFP responses. Ultimately, Staff selected Overland Consulting to perform the rate review audit which consisted of a review of APS's rate base, cost of capital, adjustor mechanisms, and rate design. Included as Attachment 1 are the resumes of the Overland consultants who contributed to this report.

ARIZONA PUBLIC SERVICE COMPANY

APS, a subsidiary of Pinnacle West Corporation ("Pinnacle West"), is the largest provider of electric service in Arizona, and serves more than 1.2 million customers in 11 of Arizona's 15 counties. At the time of the latest rate case, APS: (1) had more than 6,300 employees, (2) co-owned and operated the Palo Verde Nuclear Generating Station, (3) owned and operated six natural gas plants, two coal-fired plants, and renewable energy power generating facilities, (4) generated approximately 11% of its electricity from more than 1,200 megawatts ("MW") of renewable resources and (5) owned and operated more than 35,000 miles of transmission and distribution lines to deliver energy to its customers.[1]

SUMMARY OF RELEVANT PROCEEDINGS AND INFORMATION

2016 APS Rate Application and Commission Rate Order

On August 18, 2017, the Commission issued Decision No. 76295 (the "Decision"). Aside from the rate increase, significant changes were made to modernize the then-existing rate plans. The Decision also included the following determinations:[2]

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[1] Decision No. 76295

[2] Decision No. 76295, p.103-104.

- The fair value jurisdictional rate base for the test year ended December 31, 2015 used to establish rates was approximately $9.99 billion.
- Adjusted test year revenue was $2.89 billion.
- The equity ratio utilized in setting rates was 55.8%.
- The cost of equity was 10.0% and the embedded cost of debt was 5.13%.
- There was a net base rate increase of approximately $94.62 million. This included a non-fuel base rate increase of $148.25 million; a base fuel rate decrease of $53.63 million; and a transfer of cost recovery from adjustor mechanisms to base rates of $267.95 million which was revenue neutral.
- The Company was authorized to include twelve (12) months of post test-year plant in rate base.
- The average monthly bill increase for the residential sector is 4.5%

As stated above, this rate review it is not intended to result in an adjustment to the rates approved in the Decision. Therefore, APS did not file all of the schedules required in a full rate case proceeding, as specified in Arizona Administrative Code ("A.A.C.") R14-2-103. On April 1, 2019, for the purpose of this limited rate review, APS filed the following schedules for the calendar year ending 2018:

- Schedules A-1 through A-5 (Summary of Schedules)
- Schedules B-1 and B-5 (Rate Base Schedules)
- Schedules C-1 and C-3 (Test Year Income Statement)
- Schedules D-1 through D-4 (Cost of Capital)
- Schedules E-1 through E-9 (Financial Statements and Statistical Schedules)
- Schedules F-1 through F-3 (Projections and Forecasts)
- Schedules H-1 through H-5 (Effect of Proposed Tariff Schedules)

APS did not provide any pro forma adjustments related to the above schedules. Accordingly, APS was not required to file the following schedules in relation to this rate review:

- Schedules B-2 through B-4
- Schedule C-2
- Schedule F-4
- Schedules G-1 through G-7 (Cost of Service Analysis)

It was determined that the information provided by APS was sufficient to perform the required rate review based on the Commission's directives.

In addition to the APS pre-filed schedules and workpapers, Staff issued nine rounds of discovery that contained 150 data requests. APS provided responses to all requests made in a timely manner. Aside from written discovery, Overland and Staff attorneys also met with APS subject matter experts at APS corporate offices to discuss the material produced. On occasion, Overland conducted telephone conference calls to further address and clarify the materials relied upon in this review.

Information relied upon in the conduct of this review generally included the following materials:

- APS responses to Staff discovery requests
- Commission Decisions and Orders
- APS filed schedules
- Information from publicly available sources

All material relied upon in this report is referenced to its specific sources of information.

A full rate case proceeding would include the submittal and subsequent evaluation of all the filing requirements identified in A.A.C. R14-2-103. The accompanying rate case audit would include the detailed analysis of the following areas which is not necessarily evaluated in depth in a rate review:

- A full audit of plant investments, accumulated depreciation reserves, accumulated deferred income taxes, and the development of a company's cash working capital allowance through the completion of a lead-lag study.
- A full audit of all revenues and expenses, which would include through proposed pro-forma adjustments, the company-specific annualization and normalization of all revenues and on-going expenses, and the elimination of expenses deemed to be non-recurring.
- The evaluation of a company's cost of capital considerations, including an analysis of the appropriate company's capital structure mix to be used in calculating the weighted cost of capital, and the development of the company-specific cost of debt, and cost of preferred equity and common equity giving consideration to prevailing economic conditions and utility-specific risk factors as of the time of such evaluation.
- The development of a company-specific cost of service study leading to a rate design recommendation that fairly allocates cost recoveries among the various utility classes. Such an effort would also include development of a proof of revenue to assure that the proposed rate design does, in fact, generate the required annual revenue requirement developed through the audit of steps 1 through 3, above. Accompanying this step would be a directive to the company to submit for approval updated tariffs that support and explain how the company's rates and charges are to be applied to customer bills, and
- Detailed comparisons of current and proposed revenues and bill impacts by customer classification as well as formal notice requirements informing ratepayers of the details of the proposed rate increase.

Further, it is important to note that the processing time associated with an A.A.C. R14-2-103 rate case is generally twelve months for a Class A utility, whereas a rate review is completed in considerably less time. The additional time is required to accommodate the more in-depth evaluation of issues, such as those discussed above, and to accommodate the filing of several rounds of testimony before the start of the A.A.C. R14-2-103 rate case hearing.

By contrast, a rate review is intended to provide a snapshot of the Company's financial position or earning at any given point in time. It differs from a rate case, in that it is for informational purposes only, and is not intended to result in any change in the Company's rates. It is used to inform the Commission whether a rate case is necessary.

While this analysis is not intended to replicate what would be performed in a typical rate case, in order to determine an estimate of Commission jurisdictional revenue requirements during the period under review (2018), it is necessary to gain an understanding of the Company's financial results for the purpose of identifying underlying reasons for performance as well as to make reasonable comparisons when reaching conclusions regarding the extent of deviations from authorized returns.

The following table further provides a detail of the APS total base rate increase approved in the Decision.[3]

Table 1-1 – Summary of APS Rate Increase, 2016 Rate Case

Component	Amount (in millions)	
Non-Fuel, Non-Depreciation Increase	$	87.250
Depreciation Expense Increase	$	61.000
Non-Fuel Base Rate Increase	$	148.250
Base Fuel Rate Decrease	$	(53.626)
Net Base Rate Increase Before Adjustors	$	94.624
Transfer from Adjustor Mechanisms	$	267.953
Total Base Rate Increase	$	362.577
The 4.54% is the residential portion related to the $94.624 million net base rate increase before adjustors, which does reflect the change in depreciation expenses, but not the transfer of adjustor revenue into base rates.		

The Commission's Order authorized transition rates to be effective August 19, 2017. Customers were given until May 1, 2018, to select a new rate plan or, if the customer did not affirmatively select a new rate plan, the customer was placed on the rate plan "most like" the customer's current rate plan. New customer elections were subject to a 90-day trial period.[4] As required by the Decision, APS provided Staff with periodic reports detailing the number of customers who had chosen a new rate plan and those who were moved to a new rate plan.

ORGANIZATION OF REPORT

This Report is organized into the following sections: (1) Introduction and Executive Summary, (2) Customer Education and Outreach Program, (3) Billing Determinants and Rate Design, and (4) Rate Review. Overall

[3] Response to Discovery, Staff 6.1.

[4] Decision No. 76295, 107-109.

Findings and Recommendations are included in the Introduction and Executive Summary. Findings and Recommendations specific to each section are included at the end of the relevant section.

OVERALL FINDINGS

Customer Education and Outreach Program

CEOP Methods, Procedures and Customer Reach

1. The majority of the information communicated to customers in APS's CEOP was reasonable and understandable. Some of the most important information was conveyed in personalized letters that described the new rate plans, and in particular the new rate plans "most like" customers' existing rate plans, and the rate plans likely to be "most economical" given customers' recent historical usage.

2. The scope of the CEOP was adequate to reach APS's entire residential customer base. APS communicated the most important information concerning the new rates and rate plans through bill inserts or direct mail pieces mailed or emailed to all customers. APS provided direct communications in Spanish for customers who selected Spanish as their language for billing. Exceptions to complete customer reach for all CEOP messaging included:

   - APS did not have email addresses for approximately 45% of its residential customer base, in early 2018.
   - APS "can only send marketing emails (used to drive awareness of and participation in customer programs) to customers who have agreed to receive email communications."[5]
   - Radio and billboard advertising related to the CEOP was confined to the Phoenix metro area.
   - The following were only provided in English: (1) emails, (2) aps.com transactional pages, (3) aps.com banner ads and pop-ups, (4) IVR-based plan assistance, (5) special interest letters, (6) mass media campaigns, (7) notifications, (8) (service) plan comparison tool, and (9) peak demand calculator.

3. As part of the CEOP, APS created several tools to help customers select new rate plans and to manage their electricity usage. The most important of these was a rate comparison tool launched on the APS website that enabled customers to compare projected annual costs under their existing legacy rate plans to those associated with new rate plans. The tool remains available to customers to help select rate plans. Customer dissatisfaction caused by higher bills and the new modernized rate plans may have been worse had the rate comparison tool not been available.

4. APS's CEOP should have included more personal customer contact or outreach efforts regarding the new modernized rate plans and which plan would be of most benefit to the customer.

[5] Response to Staff data request 7.6(c).

5. APS did not explain the adjustor mechanisms in its CEOP, nor did APS clarify the fact that there would be annual updates to the adjustor mechanism billing rates occurring outside of the rate case and that such rate changes may result in an increase in customer bills. These additional bill adjustments may have been confusing to some customers, especially without notice of the adjustor mechanism changes.

CEOP Effectiveness – Non-Solar Customers

6. An analysis of a sample of 2018 customer complaints classified by APS as "rate case" related showed the following:

    - Some customers complained that the 4.5% / $6 per month average rate increase advertised by APS in 2017 understated the actual increase.
    - Some customers perceived that the rate plan transition that occurred in spring 2018, which followed the rate increase under legacy rate plans in 2017, amounted to a second increase in their utility rates.
    - Some customers may have been dissatisfied with being moved to new, sometimes differently structured rate plans, and rate plans with different peak hours, than previous rate plans.
    - Some customers moved to new rate plans may have experienced or perceived that the rate plans caused significant increases in their bills.
    - Some customers were unhappy with being placed on rate plans with a demand component.

7. The information provided by APS in its rate increase notices and personalized letters failed to convey certain important information, including:

    - The "average customer" rate increase percentage and bill impact (4.5% increase, $6 per month) disclosed in customer notices and press releases failed to adequately convey that the impact of the modernized rate design on individual customers could vary widely, and over time, depending on customer-specific circumstances and changes in other customer bill components such as adjustors and taxes and fees, and were not included in the notice regarding the average percentage or bill increase.
    - The rate plan transition letters mailed in the first few months of 2018 failed to adequately convey to customers that the additional increases in their bills, beyond those that occurred with the 2017 transition rates. The information conveyed did not include that these additional increase in bills were dependent on customer-specific circumstances, including the specific rate plans customers were on before and after the transition, and behavioral changes in energy usage patterns under the new rate plans which could minimize bill increases, such as shifting usage to accommodate the new on-peak hours and demand charges.

CEOP Effectiveness - Solar Customers

8. APS's CEOP messaging did not inform solar customers or applicants of the August 31, 2017 deadline for changing their legacy rate plans or the potential advantages of doing so.

9. Solar customer complaints show that existing customers and applicants were sometimes unaware of the potential advantages and disadvantages of different legacy rate plans under net metering because they believed that nothing was required of them to take full advantage of the net metering rules.

10. APS's rate comparison tool did not incorporate legacy rate plans or retail net metering, which, had it been available before the August 31, 2017 deadline, would have permitted solar customers to assess the benefits of different rate plans under net metering.

11. Although August 31, 2017 was the stated deadline for solar customers and applicants to change their legacy rate plan, there are examples in which APS made exceptions, allowing customers to change rate plans after the deadline.

CEOP Expenditures

12. Of the $5 million authorized, APS expended $4.85 million on the CEOP between September 2017 and February 2019. Outside (vendor) materials and services accounted for $4.28 million (88%), and $474,000 (10%) was primarily internally-incurred print shop costs, with the remaining $94,000 (2%)6 associated with payment for contract and APS employees who charged time to CEOP projects.

13. Overall, CEOP expenses incurred between September 2017 and February 2019 appear to have been reasonable, directly related to CEOP activities, and incremental to the CEOP effort.

14. The expenses associated with the three largest CEOP vendors, accounted for 62% of total CEOP vendor costs, were directly applicable to CEOP efforts and services. These costs were properly incurred and incremental to the CEOP and appropriate within the scope of the CEOP.

15. Internal cost allocations and transfers charged to CEOP were appropriate.

Billing Determinants and Rate Design

1. Although APS's 2018 base retail residential revenues were in line with 2015 estimates at an overall level, the number of medium- and large-usage customers transitioning to demand rates did not meet Company expectations. The comparison of typical bills shows that customers on demand rates were expected to see smaller overall bill increases, and actual bill savings if converting from a basic rate plan. As a result, should these customers continue on sub-optimal rate plans, APS could see higher-than-anticipated revenues in future years.

[6] This $94,000 (2%) is immaterial relative to the $5 million authorization.

2. The design of the Company's new rate plans may have incentivized demand rates over basic rates and energy rates. Analysis of typical bills indicates that rate increases for basic (one-part) and time-of-use energy (two-part) rate plans were higher than average, while demand (three-part) rate plans had lower than average increases. Furthermore, customers who were moved by APS onto a rate plan "most like" their previous rate plan were less likely to be on the most economical rate plan.

3. $6.7 million of gross margin in 2018 was associated with higher than expected revenues due to variances between the assumptions in the billing determinants utilized in the 2016 rate case and actual 2018 billing determinants. [7]

Rate Review

This report identifies several important changes since the 2016 rate case, all of which supports Staff's recommendation of a new for a rate case sooner rather than later.

1. There have been significant differences from the Company's projected 2015 customer billing determinants to the actual customer billing determinants occurring in 2018.

2. There has been noteworthy customer growth with APS stating that residential accounts have increased at a 1.7% annual rate since 2015. Due to the increase in customer growth, this could have led an increase in APS revenue for 2018 compared to 2017.

3. There has been a substantial investment in plant and infrastructure that may have increased the Company's rate base.

4. The impact of pro forma adjustments in a rate case which could include weather normalization, plant additions, interest synchronization, and normalization of income tax expense, etc. APS did not include any pro forma adjustments in the 2018 actual data.

5. According to a recent Earnings Call, the Company is actively managing its costs, and identifying additional efficiencies and savings throughout the organization.

6. According to APS, the current embedded cost of debt is 4.19%.[8] This represents a decrease from 5.13% in the 2016 rate case.

7. Based on the current market conditions and interest rates as compared to 2016, there is a possibility of changes to the cost of equity. In addition, according to APS, the new capital structure target is an equity ratio between 53.8% to 55.8%.[9]

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[7] Response to Discovery, Staff 2.11A; Performance Report. Staff is requesting that APS update this figure.
[8] Response to Discovery Staff 4.12.
[9] Response to Discovery Staff 2.7.

8. A 0.8% return on the fair value increment was approved in Decision No. 76295. However, there is a desire by the Commission to reexamine this issue in the next rate case.

9. A review of all the adjustor mechanisms in a rate case, which may lead to potential modifications.

In addition to all of the above, there are additional rate elements that need to be considered in a rate case such as: cash working capital, depreciation studies, cost of service studies, incentive compensation, pension and OPEB costs, synchronizing of interest expense, among others.

OVERALL RECOMMENDATIONS

Customer Education and Outreach Program

1. It is reasonable to have APS fund and implement a Customer Outreach and Education Program that will be developed and administered by Commission Staff. Therefore, it is recommended that Staff select and hire an independent consultant, which is to be funded by APS, to develop a program to properly and adequately educate customers on all aspects of APS's rate plans.

2. It is in the public interest for APS to provide customers with pro forma billing information on how much they would pay given their actual usage during each month if the customer was on his/her most economical plan. The Company shall continue to provide this billing information until the conclusion of the Company's next rate case or upon further Order of the Commission.

3. In future rate cases, APS should thoroughly explain and quantify the impact of adjustor mechanisms on rates.

4. It is reasonable for APS to fund and organize along with an independent third-party consultant to form a stakeholders' group to collaborate on better ways to communicate the impact of changes and adjustor mechanisms to residential customers and to make suggestions for more effective ways to educate customers on rate plans and ways to cut back on energy usage.

5. It is reasonable for APS to allow an additional opportunity for customers to switch rate plans for at least a four-month enrollment period. At any time during this enrollment period, customers will be allowed to select a different rate plan.

6. APS should identify ratepayers whose bills have increased by more than 9 percent under the new rate plans, based on 2015 Test Year determinants, and those ratepayers who are not on their most economical plan, and shall provide the most impacted ratepayers with targeted educational materials that explain: (1) the various rate plans; (2) the customer's various options; (3) comparative usage data for their current plan and their most economical plan; and (4) the opportunity to switch plans.

7. It is reasonable for APS to prepare and Staff to use a "bin-analysis" to provide more meaningful notice of estimated bill impacts to customers.

8. APS should provide grandfathered net metered solar customers with legacy demand rate (ECT-1R EPR and ECT-2 EPR) an additional opportunity to switch to a rate plan that enables them to fully benefit from net metering (E-12, ET-1 or ET-2). APS should provide notice to these customers to ensure they are made aware of the opportunity to switch to a more advantageous legacy rate plan. In addition, APS should provide educational materials informing these customers about the advantages and disadvantages of each legacy rate plan that can be paired with solar net metering. Further, the window of opportunity to switch rate plans should remain open for a reasonable time (e.g., the remainder of 2019) to ensure that all remaining demand rate solar customers have either transitioned to another legacy rate plan or positively confirmed for APS that they wish to remain on their existing demand rate.

Billing Determinants and Rate Design

1. Given the risk of variances in the distribution of customers on the various residential rate plans from those assumed in the 2016 rate case, APS should prepare a metric to track the progress of customer rate plan conversions as compared to the assumed rate case billing determinants.

2. APS should provide an update to the $6.7 million gross margin figure through May 2019 associated with the higher than projected revenues due to the variances between the assumptions in the billing determinants utilized in the 2016 rate case and actual 2018 billing determinants. APS should track and report, in this docket, to the Commissions, on a quarterly basis the amount of gross margins associated with the higher than projected revenues due to the variances between the assumptions in the billing determinants utilized in the 2016 rate case and actual 2018 billing determinants.

Rate Review

1. Due to the changing factors, as discussed in this report, including investment in plant and infrastructure that may have increased rate base, revenues and expenses, potential reduction in operations and maintenance, possible changes to cost of capital, and customer growth and billing determinants (modernized rates), which are some of the key components in the rate-making process, it is appropriate for APS to file a new rate case to reflect these changes. Therefore, it is Staff's recommendation that APS be required to file a rate case no later than October 31, 2019, utilizing a 12-month test-year period ending June 30, 2019. In doing so, the Commission, based on its rate making authority, will make the appropriate determination as to what constitutes just and reasonable rates for APS, rate payers, and stakeholders.

2. CUSTOMER EDUCATION AND OUTREACH PROGRAM

The APS CEOP was implemented in 2016 to inform and educate customers about rate changes and new rate plans. Important objectives included educating customers to help them understand the new rate plan options, encouraging customers to modify their energy usage in order to save money, and helping customers choose the rate plan most appropriate for them, given their individual circumstances.

Pursuant to Decision No. 76295, within 15 days of the Decision, APS was required to docket a draft CEOP for Commission Staff's review and approval. Stakeholders would then have 10 calendar days to provide comment and APS was required to file a final plan. APS docketed the CEOP as required, and a meeting was convened with Staff, RUCO and several stakeholders in attendance. Several concerns were expressed at the meeting, at least one by Staff and another stakeholder that the outreach should include more personal customer contact either through forums or other outreach efforts. Staff approved the plan as required by the Decision, and subsequently APS agreed to conduct several forums around the state.

Generally, the effectiveness of the CEOP in meeting the following objectives was evaluated: (1) informing customers of changes in their rates and rate plans in connection with the rate case approved in the Decision, and (2) assisting customers in selecting rate plans optimal for them offered under restructured residential tariffs. The CEOP's effectiveness for solar and non-solar customers was evaluated separately. The CEOP's effectiveness related to the transfer of adjustor mechanisms and their relationship to and impact of the rate increase is also discussed.

Specifically, the CEOP review included an evaluation of:

- The CEOP's methods, procedures, customer reach, and the understandability of information provided.
- The effectiveness of the CEOP in meeting the objective of providing customers with complete and accurate information about the rate increase and rate plan changes approved in the Decision, including the information needed to make appropriate choices among available rate plans. The effect of the changes could vary based on individual customer circumstances.
- The CEOP expenditures approved in the Decision. Also, the expenditures to determine whether they were directly associated with the CEOP, whether they were reasonable given CEOP objectives, and whether they were incremental expenditures that would not have been made absent the CEOP were examined.

CEOP METHODS, PROCEDURES, CUSTOMER REACH AND UNDERSTANDABILITY

A high-level review of the methods and procedures used by APS to communicate with customers, the customers the communications reached, and the understandability of information was performed.

Communication Methods, Content and Understandability

APS employed both mass and personalized communications in the CEOP. Mass communications included traditional advertising on radio, newspaper and billboards, and digital advertising through social media. APS also utilized email, bill notices and inserts, recorded messages in the IVR system, website postings and utility newsletters. The CEOP used personalized communications, primarily in the form of emails and letters sent with information tailored to individual customers based on their rate plans and energy usage history. These communication methods took advantage of most of the available forms and means of communication and were appropriate given the CEOP's objectives. The following table summarizes important components of the CEOP communication.

Table 2-1 – Summary of APS CEOP

Summary of APS CEOP Customer Communications, 2016-2018		
Form of Communication	Mass or Personal	Details
APS Newsletters	Mass	25 articles in APS newsletters highlighting the Shift, Stagger, Save message, and providing energy saving information and information about new service plans.
APS Website	Mass	Information on new service plans, plan comparison tools, a plan change portal, plan transition information page, demand / peak hour usage page, savings tips page, and a bill changes page. Website also includes videos providing energy savings info.
APS IVR	Mass and Personalized	On-hold messages describing service plans, and an option to permit customer selection and confirmation of service plans.
APS Bills	Mass	19 bill inserts in 2017 and 2018 with energy saving and educational information.
Personalized Direct Mail Letters	Personalized	Specialized interest letters addressing the needs of select customer groups and best rate letters informing customers of the most similar and best savings options plans based on their usage profiles.
Email	Mass	13 million "transactional" and "marketing" emails were sent covering new service plans, and energy saving information.
Social Media	Mass	Twitter (32,000 impressions) and Facebook campaigns (46,000 customers reached) provided service-plan savings information.
Other Mass Media	Mass	Radio, outdoor billboard, print and digital advertising covering new service plans. APS estimates this created 161 million impressions.
Welcome Kits	Personalized	Mailed between February and April, 2018 to 958,000 customers who switched or were transitioned by APS to a new service plan.
Source: CEOP filing, October 18, 2018, Cover Letter, pp.16-17.		

The overall message that APS communicated to unify its communications content was "Shift, Stagger, Save." Based upon the rate structure changes approved in the Decision, and particularly the elimination of the standard block rate for most large residential users and the shifting of customers to rates with time-of-use and demand components, this message was appropriate. However, for some customers, a more appropriate message could have been "shift and stagger your energy usage or you may experience substantial increases in your electric bill." In addition, the third "S" – save – may have been confusing in the sense that it could have been interpreted to mean that by selecting a new rate plan, particularly one beginning with the words "Saver Choice," without changing one's behavior, customers could expect to reduce their bills in comparison to those paid pursuant to their existing rate plans prior to the rate increase, which appears to have been true only for a limited minority of customers.

It should be noted that in its rate case application and the Decision, APS used the following tariff names for its new rate plans: (1)R-XS, (2) R-Basic, (3) R-Basic L, (4) R-TOU-E, (5) R-3 Demand. However, in its marketing tools to customers, APS used the following tariff names for its new rate plans: (1) Lite Choice, (2) Premier Choice, (3) Premier Choice Large, (4) Saver Choice, (5) Saver Choice Max. These new tariff names may have contributed to the confusion regarding rate payer expectations.

The content of the communications was generally reasonable and understandable. The most important information provided included personalized information explaining the new rate plans that were "most like" the customers' existing rate plans and those which were "most economical" given the customers' historical usage data.

One notable exception to this general conclusion is:

- The statistic communicated to customers that conveyed that the average residential bill would increase by 4.5%, or about $6 per month, was published in press releases and in a notice mailed to customers but failed to properly contextualize the statement.

Generally, however, the CEOP messaging was adequate in terms of customer reach. Specifically:

- APS's notice of intent to increase rates and change its rate design was appropriately published in newspapers with reach covering the Company's entire service territory.
- APS's notice of the change in rates was included on bills sent to all customers.
- Information on APS.com, the Company's website, was available to all customers with internet access, in early 2018.
- Bill inserts, bill messages and utility newsletters were made available to all customers in paper form or on-line, depending on selections made by customers.
- Personalized letters notifying customers of rate plan changes and providing information on the new rate plans were sent to all customers.

- In terms of language accessibility, APS stated that it provides "direct communications [in Spanish] to the customers who have selected Spanish for their bills, bill messages and direct mailings, and a dedicated phone line."

Exceptions in which the mass communication messaging did not target every APS customer included:

- Radio ads and billboard ads that were limited to the Phoenix metro area, which APS viewed as "the most cost-effective way to reach the largest amount of customers."[10] It should be noted, however, that the print and digital advertising was targeted to customers throughout Arizona.
- The following communications were provided only in English: (1) emails; (2) aps.com transactional pages; (3) aps.com banner ads and pop-ups; (4) IVR -based plan assistance; (5) special interest letters; (6) mass media campaigns; (7) notifications; (8) [service] rate plan comparison tool; and (9) peak demand calculator."[11]
- APS did not have email addresses for approximately 45% of its residential customers.
- APS's CEOP should have included more personal customer contact or outreach efforts regarding the new modernized rate plans and which plan would be of most benefit to the customer.

Customer Tools

APS created several tools to help customers in selecting new rate plans and to manage their power usage. These included:

- Rate Comparison Tool – The rate comparison tool is one of the most important components of the CEOP. Prior to the rate plan transition, it enabled a customer to compare the annual costs of their legacy rate plan to the new rate plans available. This tool directly served customers and was also employed by APS's customer service to help explain the various rate plans to customers. Based on customer complaint information, the tool appears to have been generally effective, albeit not without some limitations. The tool remains available to customers and has evolved since first introduced in 2016.
- Notification Alerts – To help manage electric usage and bills, customers can sign up to be alerted when their usage (kWh), demand (kW) or estimated bill amounts reaches designated thresholds. Only a small percentage of APS customers appear to have subscribed to this service.[12]
- Mobile Phone App – APS implemented a mobile phone application in mid-2016 to help customers manage energy usage and pay bills. As of April 4, 2019, more than 230,000 customers have downloaded the application and it has been used to complete 580,000 payment transactions. [13]

[10] Response to Staff data request 7.6(c).
[11] Response to Staff data request 7.6(a).
[12] Response to Staff data request 8.1.
[13] Response to Staff data request 5.9.

Customer Complaints

Complaints to the Commission

The following table summarizes the "informal" complaints about APS filed with the Commission beginning in 2016 through April 19, 2019.

Table 2-2– "Informal" APS Complaints filed with the Commission

"Informal" APS Complaints Filed with the Arizona Corporation Commission				
Period	Description	Complaints	Days	Annual Rate / 10,000 Cust.
2016	Post-Filing, Pre-Rate Increase	422	365	3.84
2017	Rate Increase (mid-August)	805	365	7.32
2018 through April	Rate Plan Transition	379	120	10.48
2018 May 1-Dec 31	Post-Plan Transition	645	245	8.74
2019 through April 19		171	109	5.21
Source: Arizona Corporation Commission, Consumer Services Division				

In 2014 and 2015, prior to the submission of APS's rate filing, the Commission received three informal complaints annually for every 10,000 APS customers. This number increased slightly in 2016 after APS filed in January its *intent* to file a rate case.[14] The complaint rate more than doubled after the rate increase was implemented in 2017, and it remained high as customers transitioned to new rate plans during the first four months of 2018. The high complaint rate continued through 2018 and included the first full summer experienced by customers following both the rate increase and the rate plan transition. Thereafter, during the first four months of 2019, complaints declined to approximately half their peak level, but the complaint rate was still 73% higher than it had been before the rate case was filed. It is expected that the complaint rate will increase again in 2019 as outdoor temperatures rise and customers continue to receive bills under the new rates structures.

Customer "Rate Case" Complaints

An APS database of 2018 "rate case" complaints was reviewed. Detail for a sample of 51 complaints (approximately 20% of the database) was requested and analyzed;[15] 38 of the sampled complaints were submitted by non-solar customers and 13 by solar customers. This discussion concerns non-solar complaints, which constituted 80% of the 257 complaints logged by APS in 2018 in the "rate case" category. Solar complaints are discussed separately below.

The following table summarizes complaint samples by category (what triggered the complaint) and subcategory (the primary reason or basis for the complaint as stated by the customer).

[14] APS did not file its actual rate case until June 2016.

[15] Response to Staff data request 5.13.

Table 2-3– Non- Solar Customer Complaint Sample

Non-Solar Customer Complaint Sample	
Category / Subcategory	Count
High Bill	
Unhappy with the rate increase / high bills	15
Total High Bill	15
Rate Plan Change (Notice or on the cust. bill)	
Confused about rate plan choices or unable to choose among available plans	6
Unable to select desired rate plan	3
Unhappy with high bills under available plan choices	7
Wanted to keep existing (legacy) rate plan	7
Total Rate Plan Change	23
Total Non-Solar Complaint Sample	38
Response to data request 5.13, APS customer "rate case" complaint details, multiple attachments, 20% sample.	

Effectiveness Metrics Maintained by APS

Information was requested from APS as to whether it maintained any metrics to measure the effectiveness of the CEOP and, if so, to provide the results. The response stated that "APS identified a number of metrics to be used as a means of ensuring a positive customer experience in its education, outreach and transition of customers to new rates."[16]

Customer Rate Plan Transition Metric

APS stated that this CEOP metric had a target of "all eligible customers transitioned by 5/1 [2018]." APS stated the "actual" result reflected that "1,969 customers (edge and outlier cases) were on transition rates as of 5/1." Presumably, this means that the target was to place all non-solar customers on new rate plans by the end of April 2018, and 1,969 customers had yet to be moved as of May 1, 2018.

Customer Complaint Metrics

APS indicated that its target of "zero ACC complaints" and stated that actual results met this target. Under this metric, for a complaint to be counted, the complaint had to be "substantiated." Of the 257 "rate case" complaints logged by APS in 2018, none were substantiated.[17]

[16] Response to Staff data request 6.7.

[17] For example, more than 40 rate case complaints from grandfathered solar customers were caused by the customers not being able to change legacy rate plans. As discussed more fully below, many of these customers were confused about or unaware of the need to change legacy rate plans at the time they applied for solar. In most cases, they had missed the window of time to learn about and change their rate plan. As a result of APS's response to their requests to change legacy rate plans, these customers registered complaints with the Commission. APS listed all of the complaints as "unsubstantiated" because the deadline had passed when the customers requested to change rate plans. Because the confusion and unawareness of these customers bears directly on the question of whether the CEOP accomplished its communication goals, it does not appear that the metric "zero substantiated complaints" provides information about CEOP effectiveness.

In measuring CEOP effectiveness, APS did not take into consideration trends in the total number or rate of customer complaints. As demonstrated by complaint statistics maintained by the Commission, there was a significant increase in the number and overall rate of "informal" complaints registered by the Commission during the three years from 2016 through 2018.

Evaluation of CEOP Effectiveness - Non-Solar Customers

The Decision approved higher customer rates and new modernized rate plans. This is the first time a company in Arizona implemented a rate increase in conjunction with complete structural overhaul of tariffs, particularly residential tariffs, in the same proceeding. Many of the complaints that customers voiced largely concerned features of these new modernized rate structures in conjunction with the approved rate increase, rather than directly CEOP related complaints. Customers complained of:

- The modernized Rate Design.
- The transition to a new rate plan required of most customers. In some cases, customers with one-part "standard" rates were required to move to time of use rates, or even three-part demand rates if they wanted to minimize or avoid bill increases. Some customers refused to move to rate plans with demand components even when these rate plans were estimated to be the most economical, because they weren't familiar with and didn't trust the process associated with receiving a bill with a demand component.
- Even under the most economical rate plan options available, the new rate plans caused some customers' bills to increase beyond what had occurred with the August 2017 transition rate increase, creating a perception that APS raised rates twice.
- The new rate plans, combined with the 2017 rate increases, raised electric bills more for some customers than for others.
- In some cases, even customers who made behavioral changes could not prevent bill increases due to rate plan transition.

A review of the CEOP found that many of the complaints submitted by non-solar customers concerned features of the rate increase and the modernized rate design, rather than the CEOP and its messaging. Nevertheless, CEOP messaging to non-solar customers was deficient in two respects, as discussed below, and the deficiencies appear to have contributed to customer dissatisfaction.

Rate Increase and Rate Plan Messaging Deficiencies

The most significant issues with APS's CEOP were the lack of specificity with respect to the rate increase and the variation of results customers could experience under the new rate plans.

- APS advertised the average rate increase to be 4.5% or about $6 a month per customer. Apart from the sentence "the impact on your bill will depend on your actual energy consumption," APS did not provide meaningful information about how much more of an increase some customers might experience under new rate plans, especially if they did not change their usage habits. APS did not fully explain that the 4.5% / $6 estimated monthly bill increase excluded anticipated potential changes in "adjustors," taxes and fees outside of the rate case.
- APS's primary CEOP tagline, "Shift, Stagger, and Save" and the names it gave to its new rate plans, most of which begin with the words "Saver Choice," left customers with the impression that once they moved to the new rate plans they would at best see reduced bills, or, at worst see savings after they "shifted" their energy usage. For example:

    - Some customers did not experience savings because they did not shift their usage, and / or were not defaulted to the "most economical" rate plans. In particular, customers who were placed on the time-of-use Saver Choice plan or the one-part Premier Choice plan were the least likely to "save" as a result of their new rate plan. Many of these customers perceived a second rate increase when they moved from transition rates to the new rate plans in 2018.
    - Depending on individual circumstances, electric bills could increase as a result of the change in rate plans even when customers selected the most economical rate plan and shifted their energy usage.

When APS implemented the rate increases in mid-August 2017, the Company notified customers through a bill insert. They also issued a press release intended to provide notice to the public through the media. In both cases, the information provided concerning the rate increase was limited to notification of an average of 4.5% rate increase that would increase bills for a typical residential customer by about $6 a month. The notable portion of the bill insert dealing with the rate increase and changes in rate plans is shown below.

> ***The bill impact for a residential customer using an average of 1,035 kWh per month is about a $6.16 per month increase, from $135.54 to $141.70, or 4.5 percent. The impact on your individual bill will depend on your actual energy consumption.*** *Decision No. 76295 includes new rate options, with reduced and realigned on-peak hours that create more choices for customers to control their energy costs. No immediate action is required on your part. We will send additional communications in the future about how you can choose among the new plans (emphasis added).*[18]

[18] Response to Staff data request 8.5, Attachment APSAR00013.

It is reasonable to expect that most customers consider themselves to be about average customers, and for them to expect their bills to increase by about $6 per month. During the last few months of 2017, with cooler temperatures and lower power usage, most customers probably either did not notice the August rate increase or noticed only a modest bill increase. However, in 2018, APS began to transition customers from their existing rate plans to new rate plans. Some customers were placed onto rate plans with different rate structures and customers with a time-of-use component in their rate were billed based on new peak hours. To minimize bill impacts under the new rate plans, it would have been necessary for most customers to both select the most economical rate plan available and change their energy consumption habits.

Although APS promoted its "Shift, Stagger and Save" message in various ways, the rate increase notice sent in August 2017 did little to warn customers of the potential bill impact of impending rate plan changes, or changes in certain billing categories not directly connected with the approved rate increase (adjustors, taxes and fees). Later, when the "personalized" letters were sent notifying customers that they would be transitioned to new rate plans, the letters also failed to contain any information warning customers that they could experience bill increases of substantially more than $6 per month. Instead, the letters contained only examples of the new rate plans available, which had names suggesting that customers would save money compared with their existing legacy rate plan (i.e., "Saver Choice," "Saver Choice Plus" and "Saver Choice Max").

After the transition period, some customers placed onto rate plans with titles that began with "Saver Choice," who later experienced what they viewed as a second rate increase, became dissatisfied and felt that APS had been less than transparent in its communications about what was going to happen under the modernized rates. In terms of dissatisfaction, it did not matter whether higher bills were due to changes in rate structure or to the customer's failure to shift or reduce energy usage. Evidence of this is demonstrated by customer comments in the non-solar "rate case" complaints, as summarized in the table below.

Table 2-4– Selected Customer Rate Case Comments

Selected Customer Rate Case Comments - Informal ACC Complaints Filed in 2018				
ACC Complaint	APS Complaint	Data Response Attachment	Complaint Date	Customer Comment
180111-065	2018-147711	APSAR00410	1/11/2018	I understand that APS needs to make a profit. But when APS public affairs reports that the average customer won't see more than a small increase, and using their rate comparison tool I see I'll be paying on average $75 / month more, I am outraged.
180214-058	2018-148263	APSAR00417	2/14/2018	How is it that my rate can increase twice in one year? I have noticed an increase from last year to this year . . . And now I receive a notice that I'm being taken off of my current plan and being switched to a new one that will increase my costs yet again.
180228-120	2018-148451	APSAR00422	2/28/2018	Substantial rate increase was approved based on false estimates that average bills would increase on average of $6 per month per customer. In addition new rate plans are being forced upon customers that will further increase customer cost even though consumption [is] decreased.
180507-021	2018-150227	APSAR00436	5/7/5018	The increase was advertised as $5 - $6 and stated by APS agents "may be less because you only have 5 hours of . . . peak power." In my case I . . . see a radically different increase. . . [M]y normalized rate increase is actually 11.5% . . . for the same amount of kWh. . . I have estimated out the new rate plans will at least cost $586 more this year."
180618-050	2018 - 151575	APSAR00444	6/18/2018	I could not undersand the rate plans so I called them they informed me to take the Saver Choice plan. I did and so my next bill was $732. I asked them why is it so high? I called them . . . and found out I should have took Saver Choice Max they said my bill would have been $456. . . . Keep in mind every nonth this goes on I'm paying 30 to 40% more than I'm supposed to be. . . [N]o way is this a 4.5% rate increase."
180828-118	2018 - 153800	APSAR00450	8/28/2018	Not only did APS raise their rates far more tha[n] what was approved. They purposely, simultaneiously changed their billing structure so it was more difficult to calculate the increase."
Source: Response to Staff data request 5.13				

Evaluation of CEOP Effectiveness - Solar Customers

At the end of 2018, APS had approximately 75,000 residential customers with solar panels interconnected with the Company's distribution system, representing approximately 7% of the residential customer base. The Decision required that distributed generation (DG) customers who filed an interconnection application before the rate effective date would be "grandfathered" for net metering. The specific settlement agreement language states as follows:

> *As contemplated in Decision No. 75859, grandfathered DG customers will continue to take service under full retail rate net metering and will continue to take service on their current tariff schedule for the length of the grandfathering period.*

It was also established that residential customers who submitted applications to install solar would be eligible for retail net metering under grandfathering provisions, as long as they submitted an application by the end of August 2017 and their system was approved by APS for installation by the end of February

2018. This created a surge in customer solar applications as the August deadline approached and led to confusion about installation plan requirements. The surge in demand and attendant confusion made it difficult for some applicants to get installation plans approved by APS, and so the installation approval deadline was eventually extended to the end of May 2018.

Solar Customer Outreach and Communication

APS's CEOP included communications with both solar customers and installers. Outreach included personalized letters to solar customers. The following are the important areas in which the CEOP did not adequately inform solar customers and applicants:

- Non-solar customers were permitted to apply for solar until August 31, 2017 and receive grandfathered net metering. It was important for these future solar customers to understand that the benefit they would derive from net metering was dependent on the type of legacy rate plan they had, and that the customers had until August 31 not just to apply for solar, but also to change their legacy rate plan.
- APS had a rate comparison tool which assisted customers in picking one of the new rate plans approved in the Decision. However, the tool did not provide any communication to explain the interplay between legacy rate plans and solar net metering.
- Personalized letters and other communications with *existing* solar customers also failed to explain the interplay between net metering and their legacy rate plans, or that they had until August 31 to change their rate plans.

Net Metering and Legacy Energy Rates

Existing solar customers and customers who submitted an application to APS by August 31, 2017 were "grandfathered" into net metering. This meant they were also "grandfathered" into the legacy energy rates governing what they consumed from APS, meaning they were the only customers allowed to keep these rates after the new rate plans discussed above went into effect.

In most cases, solar applicants who found they were on a legacy rate plan with a demand component may have found it beneficial to change their rate plan to one without a demand component. APS permitted this, but only until August 31, 2017, the deadline for new solar applicants to qualify for net metering. After this point in time, if an existing or future solar customer found themselves on a rate plan with a demand component, or if they were on a two-part rate, they were limited to the rate plan they were on unless they wanted to forfeit grandfathered net metering.

Customers on legacy rate plans that included demand components (tariffs ECT1R and ECT2) would probably have found it advantageous to switch to either the available time-of-use rate (ET-2) or the "standard" one-part block rate (E-12), and in some cases customers on ET-2 might also have found it advantageous to switch to E-12. However, these changes were not always made in time.

APS's messaging did not inform existing customers or new applicants of either the August 31, 2017 deadline for changing legacy rates or the potential advantages of doing so. Other APS messaging, in particular, the messages sent in personalized letters and posted on the APS.com rate comparison tool page, served to create confusion among current and future solar customers prior to the August 31, 2017 deadline. As made evident by some solar complaints, existing and future customers were sometimes unaware, before it was too late, of the potential advantages of various legacy rate plans under net metering, in part because they believed that nothing was required of them to take full advantage of the net metering rules. Messages such as the following reinforced this belief:

- **"No action is required on your part.** As a grandfathered solar customer, you will not be required to move to one of the new rate plans recently approved by the ACC." (Letter sent to existing solar customers in August 2017) (emphasis in the original).[19]
- **"Attention Solar Customers**: Please note that Grandfather (sic) Solar Customers and those Solar Customers who are in the queue awaiting interconnection are NOT required to select a new rate plan" (emphasis in original) (APS Rate Comparison Tool on the APS.com website).[20]

This confusion became evident when reviewing complaints by solar customers, most of whom complained when they found out they could not change legacy rate plans after August 31, 2017 and had been unaware of the need to do so prior to the deadline. In some cases, as customers submitted solar applications on or near the August 31, 2017 deadline, the time available to consider and request a legacy rate plan change was short. The solar application and the rate change request would have had to have been submitted on the same day (August 31, 2017). To the extent solar customers and applicants had sufficient time to consider a rate plan change, APS's rate comparison tool did not incorporate legacy rate plans or retail net metering.

Solar Customer Complaints

Of the 257 "rate case" complaints APS logged in 2018, 46 (18%) were classified as solar complaints, an amount that was disproportionately high compared with APS's solar customers, who accounted for less than 8% of the residential customer base at the end of 2018. A sample of 51 complaints included 13 of these, which were analyzed in detail.

Solar Complaints for Which APS Denied Requested Legacy Rate Changes

Most of the solar complaints in the sample resulted from customers who became aware in 2018 that they were not on the legacy energy rate they desired, but when they inquired were told by APS that they were past the deadline and could not change their rate unless they wanted to forfeit net metering.

It is clear from the complaints that some solar customers were uninformed and unaware of the need to make changes in legacy rate plans at the time they applied for solar installations. Proper messaging from APS concerning changes in legacy rate plans, targeted primarily to solar applicants, but also to their installers, would have prevented some of these complaints.

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[19] 2018 Pinnacle West Form 10-K, pp. 18 and 121 and Response to Discovery, Staff 2.38 (APSAR00294, p. 1 of 35).

[20] 2018 Pinnacle West Form 10-K, pp. 18 and 121 and Response to Discovery, Staff 2.38 (APSAR00294, p. 1 of 35).

Evaluation of CEOP Effectiveness – Adjustor Mechanisms

Based on the complaints reviewed, customers expressed confusion regarding the adjustor mechanisms relative to the average monthly bill increase of 4.5% / $6. The monthly average bill increase was derived by taking the approved 15.90% overall increase in base rates less the adjustor transfer of 11.36%. The Decision approved $267,953,000 of costs that were previously recovered through adjustor mechanisms to be transferred into base rates. The increase in base rate revenue caused by this transfer was offset by the decrease in adjustor mechanism revenue. Therefore, it was revenue neutral.

However, due to the timing of the annual updates of some of the adjustor mechanisms, the transfer was very confusing. For example, there is a one-year lag for the LFCR update. This update, and some others are outside the rate case process and therefore were not considered in the rate case. During 2018, APS had the following adjustor mechanisms which are described below:

- Power Supply Adjustor (PSA),
- Transmission Cost Adjustor (TCA),
- Lost Fixed Cost Recovery Mechanism (LFCR),
- Environmental Improvement Surcharge (EIS),
- Demand-Side Management Adjustment Charge (DSMAC),
- Renewable Energy Adjustment Charge (REAC), and
- Tax Expense Adjustment Mechanism (TEAM).

Power Supply Adjustor (PSA)

The PSA mechanism is designed to recover fuel and purchased power costs and other production-related variable costs to the extent those costs deviate from the Company's PSA cost included in base rates. The PSA typically adjusts annually at the beginning of February. In 2017, it also was adjusted in the interim when the most recent rate case was decided.

Transmission Cost Adjustor (TCA)

With the introduction of a formula rate-setting methodology at the Federal Energy Regulatory Commission (FERC) in 2008 to more accurately reflect and recover certain costs that APS incurs in providing transmission services, an adjustor was established to permit the recovery of charges for transmission costs associated with serving the Company's retail customers through an automatic adjustment mechanism. However, the Commission retains the right to suspend such changes as it sees fit.[21] The formula rate is updated annually on June 1.

Lost Fixed Cost Recovery Mechanism (LFCR)

The LFCR is designed to recover fixed costs of providing services (e.g., power poles, wires, other delivery infrastructure) that would otherwise have been collected but for mandated energy efficiency and distributed generation requirements which effectively reduce customer energy consumption.

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[21] 2018 Pinnacle West Form 10-K, pp. 18 and 121 and Response to Discovery, Staff 2.38 (APSAR00294, p. 1 of 35).

Environmental Improvement Surcharge (EIS)

The EIS provides for the recovery of the capital carrying costs of actual environmental investments made by APS not already recovered in base rates (as approved in the Decision) or through another Commission-approved adjustment.

Demand-Side Management Adjustment Charge (DSMAC)

The DSMAC provides for the recovery of demand-side management (DSM) program costs and energy efficiency performance incentives. DSM program costs are limited to those programs approved by the Commission in the annual Energy Efficiency Implementation Plan (a.k.a. the Demand Side Management Implementation Plan).[22] On residential customer bills, the DSMAC is combined with the Renewable Energy Adjustment Charge and presented as the "Environmental Benefits Surcharge".[23]

Renewable Energy Adjustment Charge (REAC)

The REAC recovers the cost of renewable energy programs included in the Company's annual Renewable Energy Standard Implementation Plan and approved by the Commission that are not otherwise recovered in base rates or other adjustor mechanisms. As noted previously, it is combined with the DSMAC on residential customer bills and presented as the "Environmental Benefits Surcharge".[24]

Tax Expense Adjustment Mechanism (TEAM)

The TEAM was approved by the Commission in the Decision to enable the pass through of material income tax effects resulting from potential federal income tax reform legislation to customers. Later that year, the Tax Cuts and Job Act was enacted, and as a result, the corporate tax rate was reduced from 35% to 21% effective on January 1, 2018.[25]

Four Corners Rate Rider and the System Benefits Adjustment

The recovery of costs for two adjustor mechanisms, the Four Corners Rate Rider and the System Benefits Adjustment, were transferred to base rates, and separate tracking of applicable costs was ended.

CEOP EXPENDITURES

The CEOP expenditures authorized in the Decision were examined to determine whether they were:

- Directly associated with the CEOP,
- Reasonable in nature given the objectives of the CEOP,
- Incremental to implementation of the CEOP (as opposed to expenditures that would have been made absent the CEOP).

[22] Response to Discovery, Staff 5.5.

[23] Response to Discovery, Staff 2.38 (APSAR00297, p. 3 of 3).

[24] Response to Discovery, Staff 2.38 (APSAR00298, p. 2 of 2 and APSAR00297, p. 3 of 3).

[25] Response to Discovery, Staff 2.38 (APSAR00299, p. 1 of 15) and 2018 Pinnacle West Form 10-K, p. 58.

CEOP Expenditure Projects and Cost Categories

APS provided details of the expenditures under the $5 million CEOP authorization and the following list of projects and expenditures that had been made through February 2019.

Table 2-5– APS CEOP Expenditures

APS CEOP Expenditures September 2017 through February 2019			
Project #	Project Title	Amount Expended	Project Description
DSM2187	Rate Analysis	$1,165,080	Analysis of rates for personalized communication with APS residential customers, including the rate comparison tool.
DSM2188	System Integration & Testing	$298,073	IT and technical implementation costs
DSM2189	Materials & Printing	$1,198,266	Print and mail personalized communications to residential customers paid to outside printers.
DSM2190	Non-Residential Education	$9,335	Communications about rate changes to non-residential customers, including a rate workshop.
DSM2197	Customer Tools	$1,364,966	Sweepstakes program costs, including the costs of 10,200 smart thermostats and 2,500 "smart plugs" given to residential customers.
DSM2198	Mass Media	$757,637	Customer communication through radio, outdoor billboards, community print ads, and social media digital and interactive ads throughout APS territory.
DSM2189	Outside Services / Agencies	$52,465	Marketing agency fees, support for conducting customer focus groups on service plan features, naming conventions and service plan options, and Spanish language consulting services.
DSM2190	Roadshows	$2,012	Travel costs associated with rate review community open hours hosted throughout Arizona to provide information and answer customer questions.
Total CEOP Projects		**$4,847,834**	
Source: Response to Staff Data Request 2.62			

APS also provided information about the nature of the costs underlying its CEOP expenditures.

Table 2-6– APS CEOP Expenditures by Cost Type

APS CEOP Expenditures by Cost Type	
Type of Cost	Amount
Outside Vendor Materials and Services	$4,279,777
APS Employee Payroll and Overheads	$94,137
Internal Cost Allocations or Transfers	$473,921
Total CEOP Expenditures by Cost Type	**$4,847,835**
Source: Response to Staff Data Request 2.62	

Review of CEOP Payments for Outside Materials and Services

Through February 2019, 39 vendors have provided materials and services categorized as authorized CEOP expenditures by APS. The three largest vendors, in terms of total payments, accounted for 62% of total CEOP expenditures on outside materials and services, and 54% of total CEOP expenditures.

Table 2-7– APS Vendors Accounting for Significant CEOP Outside Materials and Services Expenditures

APS Vendors Accounting for Significant CEOP Outside Materials and Services Expenditures		
Company	**Project**	**Amount**
GridX Inc.	Rate Analysis	$877,500
LUX Products Corp.	Customer Tools	$1,025,294
Lavidge Co.	Mass Media	$735,084
Total These Vendors		**$2,637,878**
Total Outside Provider Expenditures		$4,279,777
Pct. These Vendors		**62%**
Source: Response to Staff Data Request 5.14		

In each case, the expenditures made for services and materials related directly to customer education and outreach activities.

Services Provided by GridX Inc.

APS stated that the services provided by GridX were related to customer-specific rate analyses used in the personalized communications APS employed as part of its customer education effort. Specifically, GridX developed application programming interfaces (APIs) to provide results of APS's analysis of the costs that individual customers would incur under the new rate plans and rates authorized by the Decision. The Company further stated that GridX services directly supporting the CEOP effort and rate tools were provided from 2017 through May 2019.

The expenses for GridX were associated with work to develop and improve the APS rate plan / rate comparison tool. As such, the expenses were properly classified by APS as CEOP expenditures and directly contributed to the production of the APS rate analysis tool that was a primary component of the CEOP.

Materials Provided by Lux Products Corp.

APS's purchase order supports $728,000 of the approximately $1,025,000 in payments to Lux and lists the following items:

- 4,000 Lux GEO-WH-03 @ $90 each = $360,000
- 4,000 Lux GEO-WH-03 @ $92 each = $368,000

APS provided a change notice which supported an additional $203,000 for an additional 2,250 thermostats. APS stated the remaining $94,000 was sales taxes associated with the purchase of all of the thermostats.[26]

Services provided by Lavidge Co.

APS utilized Lavidge Co. to assist with customer communication through digital and media services. APS described the expenses associated with Lavidge as "customer communication through radio, outdoor billboards, community print ads, and social media digital and interactive ads throughout APS's service territory."[27] The total expenditures of $735,000 were appropriate.

Review of "Employee Salaries and Related Overheads" Charged to CEOP Project Orders

A total of $94,137 (2%) of the costs charged to CEOP project orders consisted of "payroll" and related payroll taxes.[28] APS stated that "[m]ost of the labor expenses associated with outreach, education, and transition of all customers were absorbed in the APS business units and not charged to the $5M allocation." This procedure is appropriate given that internal APS labor costs, apart from employees hired for the purpose of working directly on CEOP efforts, would not have been incremental to the CEOP; as such, the costs should be recoverable by APS through base rates rather than through special funding, such as the CEOP authorization. APS further stated that the $94,137 in labor expense charged to CEOP project orders was associated with contractor resources needed to supplement APS staff during "stabilization."[29]

In response to a follow-up data request, APS stated that while over 200 employees and contractors worked on the CEOP, only 12 employees charged their time to the $5 million authorization for incremental work directly tied to the outreach, education, and transition of customers. Eleven of the 12 employees work in IT and the remaining employee works in Customer Service. How much of the $94,000 in payroll is incremental contractor expense and how much is non-incremental employee payroll is unclear; however, as noted above, total payroll constitutes only about 2% of total CEOP expenses. As stated in APS's Response to Staff 2.63, APS spent approximately $3M for technology enhancements not charged to the $5M authorization. This additional $3M included incremental system upgrades and contractor labor.[30]

Review of "Internal Cost Allocations or Transfers" Charged to CEOP Project Orders

APS charged a total of $473,921 described as "internal cost allocations or transfers" to CEOP project orders.[31] Nearly all of this, $471,682, consisted of "materials and supplies" described as "printing and mailing costs for personalized communications to residential customers using APS's print shop. . . ."[32] To the extent the print shop expenses were incremental to the CEOP activities, and would not have otherwise been incurred, it was appropriate to apply the costs to CEOP project orders.

[26] Response to Staff data request 6.18 and Attachment APSAR00543 (Change Notice for additional thermostats).
[27] Response to Staff data request 5.14.
[28] Response to Staff data request 2.62, Attachment APSAR00344.
[29] Response to Staff data request 2.62.
[30] Response to Staff data request 6.19
[31] Response to Staff data request 2.62, Attachment APSAR00344.
[32] Response to Staff data request 2.62.

APS's worksheet reflected approximately 200 individual amounts charged to "DSM2189 – Materials and Printing" and totaling approximately $465,000. The associated line descriptions primarily reflected direct mail associated with customer rate migration.[33] Based on this information, the amounts that represented incremental costs associated with the CEOP are satisfactory.

FINDINGS

Customer Education and Outreach Program

CEOP Methods, Procedures and Customer Reach

1. The majority of the information communicated to customers in APS's CEOP was reasonable and understandable. Some of the most important information was conveyed in personalized letters that described the new rate plans, and in particular the new rate plans "most like" customers' existing rate plans, and the rate plans likely to be "most economical" given customers' recent historical usage.

2. The scope of the CEOP was adequate to reach APS's entire residential customer base. APS communicated the most important information concerning the new rates and rate plans through bill inserts or direct mail pieces mailed or emailed to all customers. APS provided direct communications in Spanish for customers who selected Spanish as their language for billing. Exceptions to complete customer reach for all CEOP messaging included:

    - APS did not have email addresses for approximately 45% of its residential customer base, in early 2018.
    - APS "can only send marketing emails (used to drive awareness of and participation in customer programs) to customers who have agreed to receive email communications."[34]
    - Radio and billboard advertising related to the CEOP was confined to the Phoenix metro area.
    - The following were only provided in English: (1) emails, (2) aps.com transactional pages, (3) aps.com banner ads and pop-ups, (4) IVR-based plan assistance, (5) special interest letters, (6) mass media campaigns, (7) notifications, (8) (service) plan comparison tool, and (9) peak demand calculator.

3. As part of the CEOP, APS created several tools to help customers select new rate plans and to manage their electricity usage. The most important of these was a rate comparison tool launched on the APS website that enabled customers to compare projected annual costs under their existing legacy rate plans to those associated with new rate plans. The tool remains available to customers to help select rate plans. Customer dissatisfaction caused by higher bills and the new modernized rate plans may have been worse had the rate comparison tool not been available.

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[33] Response to Staff data request 7.4, Attachment APSAR00551.

[34] Response to Staff data request 7.6(c).

4. APS's CEOP should have included more personal customer contact or outreach efforts regarding the new modernized rate plans and which plan would be of most benefit to the customer.

5. APS did not explain the adjustor mechanisms in its CEOP, nor did APS clarify the fact that there would be annual updates to the adjustor mechanism billing rates occurring outside of the rate case and that such rate changes may result in an increase in customer bills. These additional bill adjustments may have been confusing to some customers, especially without notice of the adjustor mechanism changes.

CEOP Effectiveness – Non-Solar Customers

6. An analysis of a sample of 2018 customer complaints classified by APS as "rate case" related showed the following:

   - Some customers complained that the 4.5% / $6 per month average rate increase advertised by APS in 2017 understated the actual increase.
   - Some customers perceived that the rate plan transition that occurred in spring 2018, which followed the rate increase under legacy rate plans in 2017, amounted to a second increase in their utility rates.
   - Some customers may have been dissatisfied with being moved to new, sometimes differently structured rate plans, and rate plans with different peak hours, than previous rate plans.
   - Some customers moved to new rate plans may have experienced or perceived that the rate plans caused significant increases in their bills.
   - Some customers were unhappy with being placed on rate plans with a demand component.

7. The information provided by APS in its rate increase notices and personalized letters failed to convey certain important information, including:

   - The "average customer" rate increase percentage and bill impact (4.5% increase, $6 per month) disclosed in customer notices and press releases failed to adequately convey that the impact of the modernized rate design on individual customers could vary widely, and over time, depending on customer-specific circumstances and changes in other customer bill components such as adjustors and taxes and fees, and were not included in the notice regarding the average percentage or bill increase.
   - The rate plan transition letters mailed in the first few months of 2018 failed to adequately convey to customers that the additional increases in their bills, beyond those that occurred with the 2017 transition rates. The information conveyed did not include that these additional increase in bills were dependent on customer-specific circumstances, including the specific rate plans customers were on before and after the transition, and behavioral changes in energy usage patterns under the new rate plans which could minimize bill increases, such as shifting usage to accommodate the new on-peak hours and demand charges.

CEOP Effectiveness - Solar Customers

8. APS's CEOP messaging did not inform solar customers or applicants of the August 31, 2017 deadline for changing their legacy rate plans or the potential advantages of doing so.

9. Solar customer complaints show that existing customers and applicants were sometimes unaware of the potential advantages and disadvantages of different legacy rate plans under net metering because they believed that nothing was required of them to take full advantage of the net metering rules.

10. APS's rate comparison tool did not incorporate legacy rate plans or retail net metering, which, had it been available before the August 31, 2017 deadline, would have permitted solar customers to assess the benefits of different rate plans under net metering.

11. Although August 31, 2017 was the stated deadline for solar customers and applicants to change their legacy rate plan, there are examples in which APS made exceptions, allowing customers to change rate plans after the deadline.

CEOP Expenditures

12. Of the $5 million authorized, APS expended $4.85 million on the CEOP between September 2017 and February 2019. Outside (vendor) materials and services accounted for $4.28 million (88%), and $474,000 (10%) was primarily internally-incurred print shop costs, with the remaining $94,000 (2%)35 associated with payment for contract and APS employees who charged time to CEOP projects.

13. Overall, CEOP expenses incurred between September 2017 and February 2019 appear to have been reasonable, directly related to CEOP activities, and incremental to the CEOP effort.

14. The expenses associated with the three largest CEOP vendors, accounted for 62% of total CEOP vendor costs, were directly applicable to CEOP efforts and services. These costs were properly incurred and incremental to the CEOP and appropriate within the scope of the CEOP.

15. Internal cost allocations and transfers charged to CEOP were appropriate.

RECOMMENDATIONS

Customer Education and Outreach Program

1. It is reasonable to have APS fund and implement a Customer Outreach and Education Program that will be developed and administered by Commission Staff. Therefore, it is recommended that Staff select and hire an independent consultant, which is to be funded by APS, to develop a program to properly and adequately educate customers on all aspects of APS's rate plans.

[35] This $94,000 (2%) is immaterial relative to the $5 million authorization.

2. It is in the public interest for APS to provide customers with pro forma billing information on how much they would pay given their actual usage during each month if the customer was on his/her most economical plan. The Company shall continue to provide this billing information until the conclusion of the Company's next rate case or upon further Order of the Commission.

3. In future rate cases, APS should thoroughly explain and quantify the impact of adjustor mechanisms on rates.

4. It is reasonable for APS to fund and organize along with an independent third-party consultant to form a stakeholders' group to collaborate on better ways to communicate the impact of changes and adjustor mechanisms to residential customers and to make suggestions for more effective ways to educate customers on rate plans and ways to cut back on energy usage.

5. It is reasonable for APS to allow an additional opportunity for customers to switch rate plans for at least a four-month enrollment period. At any time during this enrollment period, customers will be allowed to select a different rate plan.

6. APS should identify ratepayers whose bills have increased by more than 9 percent under the new rate plans, based on 2015 Test Year determinants, and those ratepayers who are not on their most economical plan, and shall provide the most impacted ratepayers with targeted educational materials that explain: (1) the various rate plans; (2) the customer's various options; (3) comparative usage data for their current plan and their most economical plan; and (4) the opportunity to switch plans.

7. It is reasonable for APS to prepare and Staff to use a "bin-analysis" to provide more meaningful notice of estimated bill impacts to customers.

8. APS should provide grandfathered net metered solar customers with legacy demand rate (ECT-1R EPR and ECT-2 EPR) an additional opportunity to switch to a rate plan that enables them to fully benefit from net metering (E-12, ET-1 or ET-2). APS should provide notice to these customers to ensure they are made aware of the opportunity to switch to a more advantageous legacy rate plan. In addition, APS should provide educational materials informing these customers about the advantages and disadvantages of each legacy rate plan that can be paired with solar net metering. Further, the window of opportunity to switch rate plans should remain open for a reasonable time (e.g., the remainder of 2019) to ensure that all remaining demand rate solar customers have either transitioned to another legacy rate plan or positively confirmed for APS that they wish to remain on their existing demand rate.

3. BILLING DETERMINANTS AND RATE DESIGN

OVERVIEW

In the 2016 rate case, the Commission approved a variety of rate design options for residential customers. These options include three basic service rate plans with fixed customer charges and energy charges; a rate plan with a fixed customer charge with new time-of-use energy rates; and a three-part rate plan which includes time-of-use energy rates and a demand component.

The Commission directed Staff to compare the projected billing determinants used in the 2016 rate case with actual 2018 results. The billing determinants used by APS in the Proof of Revenue from the Decision in its 2016 rate case were reviewed and compared to the Company's actual customer billing determinants used in 2018. A summary of projected 2015 and actual 2018 determinants for rate class groupings is shown below.[36]

Table 3-1 – Billing Determinants Summary

	2015 Adjusted Test Year			2018 Actual		
Rate Class	**Average Customers**	**Adjusted MWh**	**Base Revenue ($000)**	**Average Customers**	**Adjusted MWh**	**Base Revenue ($000)**
Residential						
Basic Rate Plans	420,207	2,895,587	398,475	456,301	3,583,261	494,809
Time-of-Use Energy Plans	329,997	4,523,363	620,647	372,869	5,221,299	711,080
Time-of-Use Demand Plans	263,930	5,759,371	674,708	192,225	3,850,894	457,730
Solar Rate Plans	32,856	238,216	29,154	79,421	456,767	66,569
Subtotal - Residential	1,046,990	13,416,537	1,722,984	1,100,816	13,112,221	1,730,188
General Service	127,882	14,089,945	1,463,595	131,887	14,103,822	1,475,736
Other*	2,460	509,135	64,900	2,746	514,215	65,213
Totals	**1,177,332**	**28,015,617**	**3,251,479**	**1,235,449**	**27,730,258**	**3,271,137**
* lighting and irrigation rate schedules.						

Overall, 2018 base revenue was materially consistent with APS's test year projections, as revised to adopt the approved rates in the Decision. However, there were significant variations within the residential rate classes that are further discussed in the following sections.

[36] Response to Discovery, Staff 4.5 (APSAR00370).

Table 3-2 – Average Customers

Average Customers				
Residential by Rate Type	Actual 2018	Projected 2015	Difference	%
Basic Rate Plans	456,301	420,207	36,094	9%
Time of Use - Energy	372,869	329,997	42,872	13%
Time of Use - Demand	192,225	263,930	(71,705)	(27%)
Subtotal - Non solar	1,021,395	1,014,134	7,261	1%
Solar Rate Plans	79,421	32,856	46,565	142%
Total	**1,100,816**	**1,046,990**	**53,826**	**5%**

Because the Company transitioned customers to new rate plans in May 2018, the analysis above groups customer counts in the legacy and new rate plans by the rate plan characteristics (i.e., two-part or three-part rate). The data shows that more customers were on basic rate plans than expected, and significantly fewer customers chose to move to demand rates. Participation in solar rates more than doubled from 2015 due to the accelerated adoption of rooftop solar installations.

Analysis of rate plan enrollment data as of December 31, 2018 provided additional insight into customer distribution relative to expectations from the 2016 rate case:[37]

Table 3-3 - Customers by Rate Class

Customers by Rate Class					
	Rate Class	Actual at 12/31/2018	Projected 2015	Difference	%
Basic Rates	R-XS	271,629	257,346	14,283	6%
	R-BASIC	126,049	139,107	(13,058)	(9%)
	R-BASIC L	40,482	23,417	17,065	73%
R-TOU-E		385,267	330,135	55,132	17%
TOU-D	R-2	64,673	115,116	(50,443)	(44%)
	R-3	160,471	148,045	12,426	8%
	R-TECH	18	968	(950)	(98%)
Solar Rates	E-12 EPR	29,367	12,019	17,348	144%
	ET-1 EPR	8,924	5,584	3,340	60%
	ET-2 EPR	33,915	14,019	19,896	142%
	ECT-1R EPR	553	351	202	58%
	ECT-2 EPR	2,931	883	2,048	232%

[37] APS Rate Migration Report – 12-31-18 and Response to Discovery, Staff 4.5 (APSAR00370).

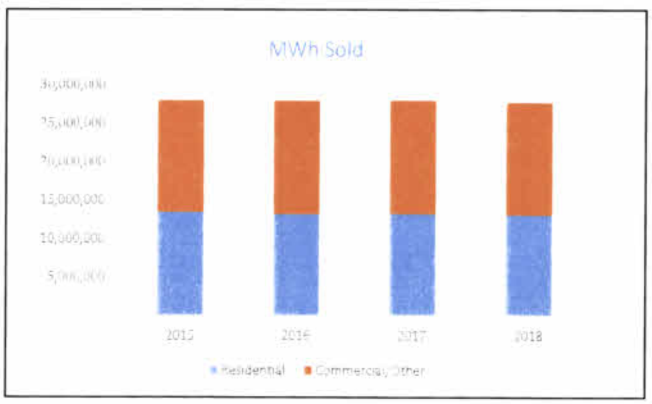
The higher number of customers on basic rates is evidenced in the R-XS and R-BASIC L rate classes. While the larger customer count in the smallest rate plan (R-XS) is comparable to the overall growth in APS's customer base, the variance in the R-BASIC L rate class suggests that customers did not migrate from basic to time-of-use rates based on the numbers the Company anticipated. More customers than expected on the demand rate class group migrated to the R-3 rate, which has higher demand charges and lower per-kWh energy charges than the R-2 rate. However, there are substantially fewer customers in the R-2 rate class than estimated.

Furthermore, the increase in solar customers between 2015 and 2018 may partly explain the lower than expected numbers in other rate classes. APS did not make any projections in the 2016 rate case for conversions to solar rates; hence, the 2015 figures represent the actual count of solar customers during that test year. These customers migrating to solar from other rate plans had a material impact on the variances in the Company's forecast.

During the transition, customers could elect to move to a qualifying rate plan. APS moved these customers onto rate plans most similar to their existing rate plan. According to the Company, 669,831 customers were defaulted to a "most like" rate plan as of May 18, 2018. However, for approximately 56% of those customers, the "most like" rate plan was not the most economical based on their prior twelve-month consumption data.[38]

CONSUMPTION ANALYSIS

Despite a 5% increase in the APS customer base, electricity consumption, as measured in megawatt-hours (MWh) sold, was relatively flat in the 2015-2018 time period.[39] In its 2018 annual SEC filing, the Company noted, "[i]mproving economic conditions and customer growth were offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives."[40] Residential customers consistently accounted for 47% of total sales throughout the period.



Electricity sales to residential customers in 2018 generally matched APS's 2015 projections in total, but showed some variability among rate types, as shown below.[41]

[38] Response to Discovery, Staff 9.1.

[39] Based on Response to Discovery, Staff 4.5 (APSAR00370) and APS FERC Form 1 Reports.

[40] Pinnacle West Form 10-K for the year ended December 31, 2018, p.63.

[41] Based on Response to Discovery, Staff 4.5 (APSAR00370).

Table 3-4 and 3-5 - MWh Sold by Rate Type and Annual kWh per Customer

MWh Sold by Rate Type				
	Actual	Projected		
Residential by Rate Type	2018	2015	Difference	%
Basic Rate Plans	3,583,261	2,895,587	687,674	24%
Time of Use - Energy	5,221,299	4,523,363	697,936	15%
Time of Use - Demand	3,850,894	5,759,371	(1,908,477)	(33%)
Subtotal - Non solar	12,655,454	13,178,321	(522,867)	(4%)
Solar Rate Plans	456,767	238,216	218,551	92%
Total	13,112,221	13,416,537	(304,316)	(2%)

Annual kWh per Customer				
	Actual	Projected		
Residential by Rate Type	2018	2015	Difference	%
Basic Rate Plans	7,853	6,891	962	14%
Time of Use - Energy	14,003	13,707	296	2%
Time of Use - Demand	20,033	21,822	(1,789)	(8%)
Subtotal - Non solar	12,390	12,995	(605)	(5%)
Solar Rate Plans	5,751	7,250	(1,499)	(21%)
Total	11,911	12,814	(903)	(7%)

The trends are similar to those discussed in the customer analysis above. Relative to the 2015 estimates, higher consumption by customers in basic rate plans was offset by lower consumption by customers on demand rate plans. Solar consumption increased commensurate with the large growth in customer base but was lower on a per-customer basis. The customers who switched to solar during the 2015-2018 timeframe used considerably less energy than those who had solar rates during the 2015 test year.

REVENUE ANALYSIS

Base Revenues

Overall, APS's 2018 base revenues from retail electric sales were consistent with the 2015 forecast, with total base revenues of $3.27 billion approximately 1% higher than the projected amount of $3.25 billion. The variations for rate types in the residential segment are summarized on the following table:[42]

Table 3-6 - Base Revenues

Base Revenues (000's)				
	Actual	Projected		
Residential by Rate Type	2018	2015	Difference	%
Basic Rate Plans	$ 494,809	$ 398,475	$ 96,334	24%
Time of Use - Energy	$ 711,080	$ 620,647	$ 90,433	15%
Time of Use - Demand	$ 457,730	$ 674,708	$ (216,978)	(32%)
Subtotal - Non solar	$ 1,663,619	$ 1,693,830	$ (30,211)	(2%)
Solar Rate Plans	$ 66,569	$ 29,154	$ 37,415	128%
Total	$ 1,730,188	$ 1,722,984	$ 7,204	0%

The distribution of revenue collected from customers in the various rate plans was very similar to the energy consumption trends noted above, with higher collections from basic rate plans and lower collections from demand rate plans.

[42] Response to Discovery, Staff 4.5 (APSAR00370).

BILL COMPARISONS

The impact of the rate increase on residential customers was analyzed by comparing typical bills for customers consuming similar amounts of energy under the legacy rate plans (prior to the application of the rate increases in August 2017) to the current tariffs. According to the Decision, the average base rate impact to residential class customers was expected to be 15.90%, which was comprised of a general rate increase (4.5%) and a reallocation of adjustor collections into the base rate (11.36%).[43] The adjustor transfers were fully offset through corresponding lower adjustor charges. The analysis focused on the impact to base rates. Thus, the full 15.90% was presumed to be the average bill increase. Similarly, the 2018 base rates did not contain the impact of changes in the adjustor mechanisms since 2015.

Basic Rate Plans

Residential customers on APS's legacy basic rate tariff E-12 that did not elect a different rate plan during the conversion were transferred onto the R-XS, R-BASIC or R-BASIC L tariffs, depending on their average monthly energy usage. To qualify for the R-XS tariff, monthly consumption must be below 500 kWh, while the R-BASIC tariff consumption must be below 1,000 kWh per month. Larger customers were moved to the R-BASIC L tariff, but this rate plan was frozen to new customers. The bill comparisons for each tariff are shown below.[44]

Table 3-7 – Typical Bill Comparison – R-XS Tariff (Lite Choice)

kWh block	2018 Rate R-XS	2015 Rate R-12	Difference	%
Summer				
0-100	$ 21.54	$ 18.24	$ 3.30	18%
101-200	$ 33.21	$ 27.92	$ 5.29	19%
201-300	$ 44.89	$ 37.61	$ 7.28	19%
301-400	$ 56.56	$ 47.30	$ 9.26	20%
401-500	$ 68.23	$ 61.12	$ 7.11	12%
Winter				
0-100	$ 21.54	$ 17.97	$ 3.57	20%
101-200	$ 33.21	$ 27.38	$ 5.83	21%
201-300	$ 44.89	$ 36.80	$ 8.09	22%
301-400	$ 56.56	$ 46.22	$ 10.34	22%
401-500	$ 68.23	$ 55.64	$ 12.59	23%
Note: This analysis focuses on the base rate impact and does not contain the adjustor transfer or any changes in the adjustor mechanisms since 2015.				

[43] See Decision No. 76295 Attachment 1, Settlement Agreement, Appendix L.

[44] The underlying data for all bill comparison schedules in this section were provided in APS's Response to Discovery, Staff 8.10 (APSAR00552).

Table 3-8 – Typical Bill Comparison – R-BASIC Tariff (Premier Choice)

kWh block	2018 Rate R-BASIC	2015 Rate R-12	Difference	%
Summer				
501-600	$ 79.90	$ 74.93	$ 4.97	7%
601-700	$ 89.15	$ 88.75	$ 0.40	0%
701-800	$ 101.54	$ 102.57	$ (1.03)	-1%
801-900	$ 113.93	$ 118.73	$ (4.80)	-4%
901-1000	$ 126.33	$ 134.90	$ (8.57)	-6%
Winter				
501-600	$ 79.90	$ 65.05	$ 14.85	23%
601-700	$ 89.15	$ 74.47	$ 14.68	20%
701-800	$ 101.54	$ 83.89	$ 17.65	21%
801-900	$ 113.93	$ 93.30	$ 20.63	22%
901-1000	$ 126.33	$ 102.72	$ 23.61	23%

Note: This analysis focuses on the base rate impact and does not contain the adjustor transfer or any changes in the adjustor mechanisms since 2015.

Table 3-9 – Typical Bill Comparison – R-BASIC L Tariff (Premier Choice Large)

kWh block	2018 Rate R-BASIC L	2015 Rate R-12	Difference	%
Summer				
1001-1100	$ 167.27	$ 151.07	$ 16.20	11%
1101-1200	$ 180.68	$ 167.23	$ 13.45	8%
1201-1300	$ 194.10	$ 183.40	$ 10.70	6%
1301-1400	$ 207.51	$ 199.57	$ 7.94	4%
1401-1500	$ 220.92	$ 215.74	$ 5.18	2%
1501-1600	$ 234.33	$ 231.90	$ 2.43	1%
1601-1700	$ 247.74	$ 248.07	$ (0.33)	0%
1701-1800	$ 261.16	$ 264.24	$ (3.08)	-1%
1801-1900	$ 274.57	$ 280.40	$ (5.83)	-2%
1901-2000	$ 287.98	$ 296.57	$ (8.59)	-3%
Winter				
1001-1100	$ 167.27	$ 112.14	$ 55.13	49%
1101-1200	$ 180.68	$ 121.55	$ 59.13	49%
1201-1300	$ 194.10	$ 130.97	$ 63.13	48%
1301-1400	$ 207.51	$ 140.39	$ 67.12	48%
1401-1500	$ 220.92	$ 149.81	$ 71.11	47%
1501-1600	$ 234.33	$ 159.22	$ 75.11	47%
1601-1700	$ 247.74	$ 168.64	$ 79.10	47%
1701-1800	$ 261.16	$ 178.06	$ 83.10	47%
1801-1900	$ 274.57	$ 187.47	$ 87.10	46%
1901-2000	$ 287.98	$ 196.89	$ 91.09	46%
Note: This analysis focuses on the base rate impact and does not contain the adjustor transfer or any changes in the adjustor mechanisms since 2015.				

For small customers on the R-XS rate plan, the rate increase was slightly higher than the average overall increase of 15.9%. The basic service charges and energy charges increased approximately 15-20% for this group.

A significant change to the basic rate plans eliminated the inclining block energy charges for summer months in the legacy R-12 tariff. While the kWh energy charges are higher in the R-BASIC and R-BASIC L tariffs relative to the R-XS tariff, they are actually lower than the R-12 legacy rate plan energy charges for all usage over 400 kWh per month. The legacy winter rates were on a single block charge which increased substantially under the new rate structure, as reflected on the tables above.

Time of Use – Energy Rate Plans

APS customers who were on a two-part rate (a basic service charge per day and an on-peak/off-peak energy charge) and did not elect a different rate plan were moved onto the R-TOU-E tariff. The new rate tariff maintained the two-part design, with the peak hours changed to 3:00 p.m. to 8:00 p.m. on non-holiday weekdays. The new tariff also introduced a super off-peak rate for certain hours during the winter billing period that is approximately 30% of the normal off-peak energy charge. The bill comparison with the legacy ET-2 tariff is shown below.

Table 3-10 – Typical Bill Comparison – R-TOU-E Tariff (Saver Choice)

Selected kWh block	2018 Rate R-TOU-E	2015 Rate ET-2	Difference	%
Summer				
901-1000	$ 148.07	$ 123.76	$ 24.31	20%
1401-1500	$ 215.70	$ 177.30	$ 38.40	22%
1901-2000	$ 283.33	$ 230.84	$ 52.50	23%
2001-2500	$ 350.96	$ 284.37	$ 66.59	23%
2501-3000	$ 418.59	$ 337.91	$ 80.68	24%
3001-4000	$ 553.84	$ 444.99	$ 108.85	24%
4001-5000	$ 689.10	$ 552.07	$ 137.03	25%
Winter				
901-1000	$ 130.33	$ 99.81	$ 30.52	31%
1401-1500	$ 189.09	$ 160.05	$ 29.04	18%
1901-2000	$ 247.86	$ 207.66	$ 40.21	19%
2001-2500	$ 306.62	$ 255.54	$ 51.08	20%
2501-3000	$ 365.38	$ 303.14	$ 62.24	21%
3001-4000	$ 482.90	$ 398.63	$ 84.27	21%
4001-5000	$ 600.43	$ 494.12	$ 106.31	22%
Note: This analysis focuses on the base rate impact and does not contain the adjustor transfer or any changes in the adjustor mechanisms since 2015.				

The increases across all usage blocks were higher than the overall 15.9% projected average. The basic service charge was reduced in the R-TOU-E, tariff, offset by higher energy rates, especially the off-peak energy charge. The severity of the increases in the winter period was mitigated somewhat by the new super off-peak energy charge.

Demand Rate Plans

APS offers two demand rate plans in its current offerings. These rate plans have a three-part structure with a basic service charge, a demand charge based on the highest hourly on-peak demand, and an energy charge. The R-2 tariff (Saver Choice Plus) has a lower demand charge and higher energy charge than the R-3 tariff. Most APS customers on a demand rate as of December 31, 2018 were on the R-3 tariff. A comparison of typical bills over a selection of usage blocks from the legacy ECT-2 demand rate to the R-3 tariff is below.

Table 3-11 – Typical Bill Comparison – R-3 Demand Tariff (Saver Choice Max)

Selected kWh block	2018 Rate R-3	2015 Rate ECT-2	Difference	%
Summer				
901-1000	$ 137.71	$ 143.53	$ (5.81)	-4%
1401-1500	$ 208.87	$ 202.22	$ 6.65	3%
1901-2000	$ 271.32	$ 232.57	$ 38.75	17%
2001-2500	$ 330.28	$ 287.22	$ 43.06	15%
2501-3000	$ 385.76	$ 321.62	$ 64.15	20%
3001-4000	$ 498.45	$ 422.81	$ 75.64	18%
4001-5000	$ 576.26	$ 498.36	$ 77.91	16%
Winter				
901-1000	$ 97.29	$ 109.66	$ (12.37)	-11%
1401-1500	$ 142.59	$ 155.13	$ (12.54)	-8%
1901-2000	$ 186.67	$ 178.63	$ 8.04	5%
2001-2500	$ 228.30	$ 220.76	$ 7.54	3%
2501-3000	$ 267.48	$ 247.98	$ 19.50	8%
3001-4000	$ 349.51	$ 324.77	$ 24.74	8%
4001-5000	$ 415.64	$ 383.89	$ 31.75	8%
Note: This analysis focuses on the base rate impact and does not contain the adjustor transfer or any changes in the adjustor mechanisms since 2015.				

In most instances, bills were projected to have a lower than the 15.9% overall average increase, and in some cases, bills were expected to decrease. The R-3 tariff had a lower basic service charge and lower average increases in per-kWh energy charges than other rate plans. These were somewhat offset by demand charge increases of approximately 30%, which had a greater impact on summer bills that typically have higher peak demand.

Rate Plan Transition

As discussed in other sections of this report, customers were encouraged to compare estimated rates on the various rate plans and select the most economical rate plan based on their consumption patterns. The typical bills for a selection of usage blocks under various transition scenarios were analyzed to determine the impacts of moving to a different rate plan, as shown on the tables below.

Tables 3-12 and 3-13 – Typical Bill Comparison – Transition from Basic Rate Plans

Conversion from Basic Rate Tariff to Energy Tariff				
Selected kWh block	2018 Rate R-TOU-E	2015 Rate E-12	Difference	%
Summer				
901-1000	$ 148.07	$ 134.90	$ 13.17	10%
1401-1500	$ 215.70	$ 215.74	$ (0.04)	0%
1901-2000	$ 283.33	$ 296.57	$ (13.24)	-4%
2001-2500	$ 350.96	$ 377.41	$ (26.45)	-7%
2501-3000	$ 418.59	$ 458.24	$ (39.65)	-9%
3001-4000	$ 553.84	$ 630.81	$ (76.97)	-12%
4001-5000	$ 689.10	$ 803.38	$ (114.28)	-14%
Winter				
901-1000	$ 130.33	$ 102.72	$ 27.61	27%
1401-1500	$ 189.09	$ 149.81	$ 39.29	26%
1901-2000	$ 247.86	$ 196.89	$ 50.97	26%
2001-2500	$ 306.62	$ 243.98	$ 62.65	26%
2501-3000	$ 365.38	$ 291.06	$ 74.32	26%
3001-4000	$ 482.90	$ 385.23	$ 97.67	25%
4001-5000	$ 600.43	$ 479.40	$ 121.03	25%

Conversion from Basic Rate Tariff to Demand Tariff				
Selected kWh block	2018 Rate R-3	2015 Rate E-12	Difference	%
Summer				
901-1000	$ 137.71	$ 134.90	$ 2.81	2%
1401-1500	$ 208.87	$ 215.74	$ (6.87)	-3%
1901-2000	$ 271.32	$ 296.57	$ (25.25)	-9%
2001-2500	$ 330.28	$ 377.41	$ (47.13)	-12%
2501-3000	$ 385.76	$ 458.24	$ (72.48)	-16%
3001-4000	$ 498.45	$ 630.81	$ (132.36)	-21%
4001-5000	$ 576.26	$ 803.38	$ (227.12)	-28%
Winter				
901-1000	$ 97.29	$ 102.72	$ (5.43)	-5%
1401-1500	$ 142.59	$ 149.81	$ (7.22)	-5%
1901-2000	$ 186.67	$ 196.89	$ (10.22)	-5%
2001-2500	$ 228.30	$ 243.98	$ (15.68)	-6%
2501-3000	$ 267.48	$ 291.06	$ (23.58)	-8%
3001-4000	$ 349.51	$ 385.23	$ (35.72)	-9%
4001-5000	$ 415.64	$ 479.40	$ (63.76)	-13%

Note: This analysis focuses on the base rate impact and does not contain the adjustor transfer or any changes in the adjustor mechanisms since 2015.

Table 3-14 – Typical Bill Comparison – Transition from Energy Rate Plan to Demand Rate Plan

Selected kWh block	2018 Rate R-3	2015 Rate ET-2	Difference	%
Summer				
901-1000	$ 137.71	$ 123.76	$ 13.95	11%
1401-1500	$ 208.87	$ 177.30	$ 31.57	18%
1901-2000	$ 271.32	$ 230.84	$ 40.49	18%
2001-2500	$ 330.28	$ 284.37	$ 45.91	16%
2501-3000	$ 385.76	$ 337.91	$ 47.85	14%
3001-4000	$ 498.45	$ 444.99	$ 53.46	12%
4001-5000	$ 576.26	$ 552.07	$ 24.19	4%
Winter				
901-1000	$ 97.29	$ 99.81	$ (2.52)	-3%
1401-1500	$ 142.59	$ 160.05	$ (17.46)	-11%
1901-2000	$ 186.67	$ 207.66	$ (20.99)	-10%
2001-2500	$ 228.30	$ 255.54	$ (27.24)	-11%
2501-3000	$ 267.48	$ 303.14	$ (35.66)	-12%
3001-4000	$ 349.51	$ 398.63	$ (49.12)	-12%
4001-5000	$ 415.64	$ 494.12	$ (78.48)	-16%
Note: This analysis focuses on the base rate impact and does not contain the adjustor transfer or any changes in the adjustor mechanisms since 2015.				

Customers with low energy consumption (less than 500 kWh per month) were moved to the R-XS rate tariff and were not expected to materially benefit from another rate plan. For moderate and large customers on basic rate plans, most would see lower than average bill increases, and in many cases would see bills decrease on a demand tariff. While the introduction of a demand charge would change the billing structure for those customers moving from basic energy rate plans, substantially lower per-kWh energy charges and lower basic service charges would potentially offset the demand charge. The cost advantages from these rate plans were higher as consumption increased.

The change from the basic rate tariffs to a time-of-use energy tariff had a mixed effect. In similar fashion to customers previously on time-of-use rate plans, the elimination of the summer inclining block charge led to projected reductions in the summer bills. However, the winter bills were estimated to increase more than the 15.9% average due to higher per-kWh energy charges.

Adjustor Mechanisms

An APS residential customer's bill consists of two components: (1) the base rate, which is based on the customer's corresponding rate schedule; and (2) the adjustor mechanisms, which are additional Commission-approved charges. The adjustor mechanisms are designed to match, in a more timely manner, the amount paid by customers for electricity with the actual costs to supply it. Some adjustor mechanisms fund certain program costs (e.g. demand-side management and renewable energy).

FINDINGS

1. Although APS's 2018 base retail residential revenues were in line with 2015 estimates at an overall level, the number of medium- and large-usage customers transitioning to demand rates did not meet Company expectations. The comparison of typical bills shows that customers on demand rates were expected to see smaller overall bill increases, and actual bill savings if converting from a basic rate plan. As a result, should these customers continue on sub-optimal rate plans, APS could see higher-than-anticipated revenues in future years.

2. The design of the Company's new rate plans may have incentivized demand rates over basic rates and energy rates. Analysis of typical bills indicates that rate increases for basic (one-part) and time-of-use energy (two-part) rate plans were higher than average, while demand (three-part) rate plans had lower than average increases. Furthermore, customers who were moved by APS onto a rate plan "most like" their previous rate plan were less likely to be on the most economical rate plan.

3. $6.7 million of gross margin in 2018 was associated with higher than expected revenues due to variances between the assumptions in the billing determinants utilized in the 2016 rate case and actual 2018 billing determinants. 45

[45] Response to Discovery, Staff 2.11A; Performance Report. Staff is requesting that APS update this figure.

RECOMMENDATIONS

1. Given the risk of variances in the distribution of customers on the various residential rate plans from those assumed in the 2016 rate case, APS should prepare a metric to track the progress of customer rate plan conversions as compared to the assumed rate case billing determinants.

2. APS should provide an update to the $6.7 million gross margin figure through May 2019 associated with the higher than projected revenues due to the variances between the assumptions in the billing determinants utilized in the 2016 rate case and actual 2018 billing determinants. APS should track and report, in this docket, to the Commissions, on a quarterly basis the amount of gross margins associated with the higher than projected revenues due to the variances between the assumptions in the billing determinants utilized in the 2016 rate case and actual 2018 billing determinants.

For this review, it is necessary to analyze the Company's financial results for the purpose of identifying underlying reasons for performance as well as to make reasonable comparisons when reaching conclusions regarding the extent of changes since the 2016 rate case. The rest of this section provides these analyses.

In a full rate case proceeding, the Commission is required to establish rates that are just and reasonable. In so doing, the Commission will consider a variety of factors and the financial condition of a company at a point and time (the test-year). Some of the key components that would lead to an upward or downward adjustment in a typical rate case are discussed below.

RATE BASE

The 2018 year-end original cost jurisdictional rate base submitted by the Company totaled $7,876,152,000.[46] This compares to the jurisdictional original cost rate base proposed by APS in the last rate case of $6,771,151,000 for the 2015 calendar test year, which included proposed adjustments to recognize post-test year plant additions through June 30, 2017. The $1.1 billion change in rate base is almost exclusively due to the increase in net utility plant in service (gross plant less accumulated depreciation), which increased from $9.092 billion in 2015 to $10.289 billion in 2018.[47]

Gross Utility Plant in Service

Gross jurisdictional utility plant in service increased from a projected $15,436,960,000 in mid-2017 to $16,537,707,000 in late 2018 according to APS. The principal reason for this increase is the transfer of costs from construction work in progress to utility plant in service, otherwise referred to as plant closings. Focusing on the 17 months ended December 31, 2018 (August 1, 2017 – December 31, 2018), the most significant projects closed into utility plant in service included:[48]

- $215.9 million associated with Four Corners Unit 4 permitting, engineering, and construction of Selective Catalytic Reduction equipment,
- $209.8 million associated with Four Corners Unit 5 permitting, engineering, and construction of Selective Catalytic Reduction equipment, and
- $92.2 million associated with a 500 kV line from Sun Valley to Morgan.

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[46] Response to pre-filed Discovery, Staff 1.1 (Schedule B-1).

[47] Response to pre-filed Discovery, Staff 1.1 (Schedule B-1) and Company rate filing in Docket Nos. E-01345A-16-0036 and E-01345A-16-0123 (Schedule B-1).

[48] Responses to Discovery, Staff 2.32 and Version 2 of Staff 2.34. Since Construction Work in Progress (CWIP) is not included in rate base, transfers of dollars from CWIP to Utility Plant in Service (plant closings) are a primary reason that Utility Plant in Service and, correspondingly, rate base are increasing during this time period.

These three projects make up 27.2 % of the total plant closings to utility plant in service ($1.903 billion) in the seventeen months ending December 31, 2018.[49] No other specific project closed by the Company during this time period exceeded $23.9 million.[50]

With respect to the first two plant closings listed above, as part of the settlement agreement that was associated with the 2016 rate case, "the parties agree[d] that this Docket shall remain open for the sole purpose of allowing APS to file a request that its rates be adjusted no later than January 1, 2019 to reflect the proposed addition of Selective Catalytic Reduction ("SCR") equipment at Four Corners . . .."[51]

On April 27, 2018, APS filed a request for an approval of an adjustment to recover the costs associated with the Selective Catalytic Reduction equipment at Four Corners. While a hearing has been held on the matter and an Administrative Law Judge recommendation has been released, no Commission decision had been issued as of late April 2019.[52]

Capital Expenditures

These plant closings largely correspond with the capital expenditures that APS made in 2017 and 2018 (capital expenditures are classified initially as Construction Work in Progress and later transferred to Utility Plant in Service). The following table identifies the projects with the highest capital spending in 2017 and 2018 along with a summary of other projects:

49 Response to Discovery, Staff 2.32.

50 Two blanket work orders, Pad-Mounted Underground Transformers ($41.9 million) and Asset Retirement Obligations ($28.7 million), were slightly in excess of the $23.9 million.

51 Decision No. 76295 in Docket Nos. E-01345A-16-0036 and E-01345A-16-0123, p. 12 of 32.

52 Recommendation of ALJ Martin dated November 27, 2018 in Docket Nos. E-01345A-16-0036 and E-01345A-16-0123, p. 8 and e-mail received from Commission Staff on April 24, 2019.

Table 4-1 – Capital Expenditures 2017-2018

APS Capital Expenditures 2017 - 2018 (in 000's)				
Project Description	**Project ID**	**Actual**	**Budget**	**Fav / (Unfav)**
Ocotillo Modernization Project	OCC07633	$ 231,258	$ 231,362	$ 104
Four Corners Unit 5 SCR System	FBC90401	76,620	75,704	(916)
Sun Valley TS5-Morgan TS9 500	TAIMPSNVLMGN	69,629	71,000	1,371
Four Corners Unit 4 SCR Sytem	FCC03864	68,824	70,699	1,875
Nuclear Fuel	NUCLEAR FUEL	68,563	68,962	399
Construction Overhead-Engineering & Supervision	EDES OVERHD-99	55,904	48,138	(7,766)
Service and Line Extensions-Residential	RESIDENTIAL	32,337	36,854	4,517
Other		737,623	734,000	(3,623)
2017 Subtotal		**$ 1,340,758**	**$ 1,336,719**	**$ (4,039)**
Ocotillo Modernization Project	OCC07633	109,401	113,779	4,378
Nuclear Fuel	NUCLEAR FUEL	71,440	71,863	423
Construction Overhead-Engineering & Supervision	EDES OVERHD-99	61,629	57,057	(4,572)
Service and Line Extensions-Residential	RESIDENTIAL	36,538	32,773	(3,765)
Transformers	TRANSFORMER	30,721	27,895	(2,826)
Other		893,142	877,633	(15,509)
2018 Subtotal		**$ 1,202,871**	**$ 1,181,000**	**$ (21,871)**
2017 and 2018 Total		**$ 2,543,629**	**$ 2,517,719**	**$ (25,910)**
Source: Supplemental Response to Discovery, Staff 2.34.				

Aside from the projects related to SCR equipment additions at the Four Corners power plant, APS devoted extensive resources on the following:

- Ocotillo Modernization Project – installation of five new simple-cycle gas turbines, which will add 510 MW of production;[53]
- Nuclear Fuel – refinement, conversion, enrichment, and fabrication of nuclear fuel materials into assemblies and components;
- Construction Overhead-Engineering & Supervision – costs incurred in the course of normal business, but which cannot be directly assigned to a particular function or activity;
- Service and Line Extensions-Residential – costs to provide new service or upgraded service to residential customers; additions of new revenue;
- Transformers – pre-capitalized cost of transformer purchases that are used for additions and replacements in the distribution system;

Of the capital expenditures made in 2017 and 2018, a portion was subject to recovery through adjustor mechanisms. $211,227,000 and $189,703,000 of capital spending on projects with actual or budgeted spending of $2 million or more was recovered through the Transmission Cost Adjustor in 2017 and 2018, respectively. This included the Sun Valley TS5-Morgan TS9 500 project that is listed in the preceding table.

[53] Parties to the settlement agreement in the last rate case were aware of the Ocotillo Modernization Project and took steps to defer the costs of owning, operating, and maintaining this plant for possible future rate recovery (see Decision No. 76295 in Docket Nos. E-01345A-16-0036 and E-01345A-16-0123, p. 13 of 32).

Capital carrying costs associated with $24,457,000 and $13,859,000 of capital spending in 2017 and 2018, respectively, was recovered through the Environmental Improvement Surcharge. Finally, $6,354,000 was recovered in 2018 through the Renewable Energy Adjustment Charge.[54]

As the preceding table demonstrates, capital spending in the past two years was limited largely to the amounts budgeted by corporate management. For the two years ended December 31, 2018, capital expenditures exceeded budget by a cumulative $25.9 million (1.0%).

Revenues and Expenses

APS's revenues have changed due to growth in the number of customers served, the ongoing migration of customers to alternative rate options, and the accompanying changes in customer usage patterns. Typically, expenses include costs incurred to run the Company. For instance, this would include operations and maintenance expenses and general and administrative expenses. According to the Earnings Call, APS is actively managing its costs and identifying additional efficiencies and savings throughout the organization, which may suggest a decrease in the level of recoverable operating expenses. All of the Company's expenses will be audited in a full rate case.

Because the rate review information and data provided did not include pro forma adjustments, and although jurisdictional financial data for 2018 was provided, no comparative information was provided for previous years. However, considering all of the factors discussed herein all of this will be audited in a rate case.

COST OF CAPITAL

The cost of capital used in the revenue requirement formula depicts the rate of return on rate base required to recover the Company's weighted cost of long-term debt, cost of common equity, and cost of preferred equity. The cost of equity in the 2016 APS rate case was determined to be 10%. However, it should be noted that the cost of equity is typically one of the most controversial areas of focus in any rate case because it changes over time and must be determined from a judgmental assessment of comparable risk. The cost of debt and the cost of preferred equity are much less controversial and can be determined from an assessment of company-specific data. Because the cost of capital is a weighted calculation of changes in the cost of the individual components (debt, common, and preferred equity), it must be evaluated as well as changes in the percent of each component within the Company's capital structure mix.

The embedded cost of debt in the 2016 rate case was 5.13%. According to APS, the new cost of debt as of December 31, 2018 was lower at 4.73%.[55] This represents a change in the actual cost of debt. This in turn will affect the weighted cost of capital which is one element in an upward or downward adjustment

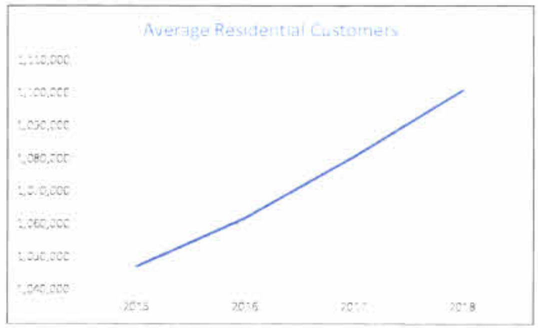
[54] Obtained or derived from the Response to Discovery, Staff 6.4. EIS and REAC spending amounts were also limited to projects that had actual or budgeted spending equal to or in excess of $2 million per year.

[55] APS workpaper A-3 p. 2 of 2.

in a rate case. Now, according to APS, the embedded cost of debt is 4.19%.[56] The lower cost of debt will need to be reflected in APS's next rate case.

The Decision provided for a 55.8% equity ratio. APS currently targets an equity ratio of 53.8% to 55.8%.[57] The equity ratio as of December 31, 2018, was 54.69%. Cost of equity is more expensive leading to an equity ratio which may reflect a downward movement. However, depending on the timing of when APS files a new rate case and the proxy group, the results may change.

CUSTOMER GROWTH ANALYSIS



APS experienced consistent growth in its residential and commercial customer bases between 2015 and 2018. While growth in commercial customers has increased, on average, 1% annually, residential accounts, which comprise approximately 90% of APS's customer base, have increased at a faster 1.7% annual rate since 2015. Residential customer growth has increased at an even faster pace over the past two years.[58,59] A new rate case filing would take this new growth into account.

ADJUSTOR MECHANISMS

Pursuant to the Decision, approximately $268 million of costs previously recovered through adjustor mechanisms were transferred into base rates, and prospective tracking of two of the nine adjustors were ended (Four Corners Rate Rider and Systems Benefit Adjustment). In addition, to base rates, which account for a significant portion of the revenues collected by APS, the Company employs a number of different adjustor mechanisms, as previously discussed. Some of these adjustor mechanisms are designed to match in a more timely manner, the amount paid by customers for electricity with the actual costs to supply it. Other adjustor mechanisms fund certain program costs (e.g. demand-side management and renewable energy). In addition, in the future, the impact of the adjustor mechanisms on rates should be thoroughly explained and quantified to customers.

FINDINGS

This report identifies several important changes since the 2016 rate case, all of which supports Staff's recommendation of a new for a rate case sooner rather than later.

[56] Response to Discovery, Staff 4.12.

[57] Response to Discovery, Staff 2.7.

[58] Based on Response to Discovery, Staff 4.5 (APSAR00370) and APS FERC Form 1 Reports.

[59] In Pinnacle West's News Release on 2019 first-quarter earnings, dated May 1, 2019, it states "customer growth a solid 1.9 percent as Arizona's economy continues to expand".

1. There have been significant differences from the Company's projected 2015 customer billing determinants to the actual customer billing determinants occurring in 2018.

2. There has been noteworthy customer growth with APS stating that residential accounts have increased at a 1.7% annual rate since 2015. Due to the increase in customer growth, this could have led an increase in APS revenue for 2018 compared to 2017.

3. There has been a substantial investment in plant and infrastructure that may have increased the Company's rate base.

4. The impact of pro forma adjustments in a rate case which could include weather normalization, plant additions, interest synchronization, and normalization of income tax expense, etc. APS did not include any pro forma adjustments in the 2018 actual data.

5. According to a recent Earnings Call, the Company is actively managing its costs, and identifying additional efficiencies and savings throughout the organization.

6. According to APS, the current embedded cost of debt is 4.19%.[60] This represents a decrease from 5.13% in the 2016 rate case.

7. Based on the current market conditions and interest rates as compared to 2016, there is a possibility of changes to the cost of equity. In addition, according to APS, the new capital structure target is an equity ratio between 53.8% to 55.8%.[61]

8. A 0.8% return on the fair value increment was approved in Decision No. 76295. However, there is a desire by the Commission to reexamine this issue in the next rate case.

9. A review of all the adjustor mechanisms in a rate case, which may lead to potential modifications.

In addition to all of the above, there are additional rate elements that need to be considered in a rate case such as: cash working capital, depreciation studies, cost of service studies, incentive compensation, pension and OPEB costs, synchronizing of interest expense, among others.

RECOMMENDATIONS

1. Due to the changing factors, as discussed in this report, including investment in plant and infrastructure that may have increased rate base, revenues and expenses, potential reduction in operations and maintenance, possible changes to cost of capital, and customer growth and billing determinants (modernized rates), which are some of the key components in the rate-making

[60] Response to Discovery Staff 4.12.

[61] Response to Discovery Staff 2.7.

process, it is appropriate for APS to file a new rate case to reflect these changes. Therefore, it is Staff's recommendation that APS be required to file a rate case no later than October 31, 2019, utilizing a 12-month test-year period ending June 30, 2019. In doing so, the Commission, based on its rate making authority, will make the appropriate determination as to what constitutes just and reasonable rates for APS, rate payers, and stakeholders.

Attachment 1

Howard E. Lubow, President

Overland Consulting | 11551 Ash Street, Suite 215 | Leawood, KS 66211 | 913-599-3323
hlubow@overlandconsulting.com

General

Mr. Lubow is President of Overland Consulting. He has more than 30 years of experience as a public utility consultant. His consulting engagements have encompassed a broad spectrum of management, finance, and regulatory issues for electric, gas, water, pipeline, and telephone utilities. Recent project experience includes focused management audits, analysis of utility diversification and acquisition plans, prudence studies, accounting systems design, cost-of-service determination and allocation, utility property valuation, rate of return determinations, and rate design issues. Mr. Lubow has testified in more than 100 regulatory and civil litigation proceedings and has testified in approximately 20 jurisdictions through the country.

Professional Work History

Overland Consulting *1991 – Present*
President

Responsible for administration and review of management auditing, regulatory consulting, and litigation support services. Provide expert witness services in projects involving decision analysis, damages assessment, ratemaking, valuation, and accounting.

Kansas Pipeline Company *1997 – 1999*
Executive Vice President, Chief Operating and Financial Officer

Responsible for the day-to-day operations of this natural gas pipeline, as well as direct responsibilities associated with the financial, accounting, and regulatory functions of the Company. Implemented a reengineering and downsizing program that resulted in a major reduction in operating expenses. Negotiated new gas supply and transportation contracts. Renegotiated credit lines on more favorable terms. Responsible for the negotiation and acquisition of a natural gas marketing company. Developed and implemented a management incentive program for senior executives. Developed due diligence and presentation materials relied upon by potential buyers of Kansas Pipeline assets.

Amerifax, Inc. (Americonnect) *1990 – 1991*
Chief Executive Officer

Directed the IPO for this telecommunications switchless rebiller. The company implemented a national marketing program, focusing primarily in the Midwest. After five years, the company was acquired for approximately three times its IPO valuation.

LMSL, Inc. *1983 – 1990*
President

Responsible for administration and review of regulatory services projects and research studies. Expert witness in regulatory proceedings. Director of special projects including management audits, financing feasibility studies, property acquisition and merger feasibility studies, and development of innovative solutions to current regulatory issues.

Drees Dunn Lubow & Company *1976 – 1982*

Managing Partner

Responsible for projects for utility clients. Responsibility included financial and managerial analysis of public utility companies and the presentation of expert testimony before regulatory commissions.

Troupe, Kehoe, Whiteaker & Kent *1972 – 1976*

Senior Regulatory Consultant

Responsible for special services work for utility clients, including accounting systems design, cost-of-service determination and allocation, budgeting, and rate designs. Performed fair value determinations, developed cost analysis studies, curtailment requirements analysis, and forecasts of utility operations.

Kansas City Power & Light Company *1968 – 1972*

Senior Accountant

Analyzed accounting and reporting procedures, taxes, and costs of operations. Assisted in the preparation of Federal and State income tax returns and the Annual Report to stockholders. Assisted with rate filings in Kansas and Missouri. Developed tax basis property accounting system.

PROFESSIONAL EXPERIENCE

ELECTRIC AND GAS

- Engagement Director/Project Manager in the review of a proposed merger between AltaGas Ltd., WGL Holdings, Inc., and Washington Gas Light Company on behalf of the Maryland PSC. Appeared as a key witness, addressing holding company conditions, finance and corporate governance matters, ring fencing policies, the merger impact on utility rates, adequacy of merger commitments, deal terms, and impacts of capital expenditures on credit ratings, and financial integrity of the utility post-acquisition.

- Project Director in a management and operations audit of New York New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, both subsidiaries of Avangrid Networks, the ultimate parent being Iberdrola, S.A. headquartered in Madrid, Spain. The scope of the review included corporate governance, finance, electric and gas planning, project and work management, and customer service functions.

- Engagement Director in a comprehensive management and operations audit of Central Hudson, on behalf of the New York State PSC. The audit includes a comprehensive assessment of the utility's construction program planning processes and an evaluation of the efficiency of the utility's operations with a focus on opportunities to improve performance.

- Project Director in a focused review of the general rate application of Southwest Gas Corporation, on behalf of the Arizona Corporation Commission. The review addresses procurement activities, depreciation studies, rate design and revenue decoupling, and a class cost of service study.

- Project Director in the review of the proposed merger between Exelon Corporation and Pepco Holdings, Inc., on behalf of the Maryland PSC. Appeared as the lead policy witness, addressing financial, governance, and rate issues implicit in the merger review.

- Project Director in the review of the proposed merger between Exelon Corporation and Pepco Holdings, Inc., on behalf of the Delaware PSC. Prepared written testimony, addressing financial, governance, and rate issues implicit in the merger review.

- Project Director in a focused audit of all major electric and gas utilities in the State of New York. The audit addressed the reliability and comparability of operating metrics reported to the Commission concerning electric reliability, gas safety, and customer service.
- Project Manager in a management audit of South Jersey Gas Company and its parent, South Jersey Industries. The audit addressed compliance with affiliate transaction rules, as well as all primary functional areas of utility and corporate operations. Specifically addressed corporate governance, finance, gas operations, gas safety, and gas procurement functions within the audit. Reviewed implications of diversification on utility risk.
- Project Director in a focused review of PG&E practices associated with their gas transmission system. This project arose from the San Bruno incident, which led to intense investigations at the state and federal level. Overland was retained by the California PUC to audit the management operations and financial commitments of PG&E necessary to assess the adequacy of resources supporting gas safety policies and procedures. In this context, capital expenditures and operating budgets were reviewed in relation to regulatory commitments reflected in customer rates over time. Provided testimony on the financial capacity of PG&E to support capital investments needed to upgrade gas safety and reliability across the transmission system, as well as to consider the implications of potential fines under review by the CPUC.
- Project Director in a focused review of PG&E gas distribution gas safety and reliability financial commitments and operations procedures. Considered the adequacy of financial commitments and management practices, as well as consequences of resource restrictions on safety and reliability metrics. Results were provided in a report filed with the CPUC on behalf of the Public Safety Division.
- Project Director in a focused audit of National Grid service and parent company charges to New York jurisdictional utilities. The audit included a review of internal control procedures, as well as an in-depth review of transactions over a 20-month period, ultimately associated with jurisdictional cost-of-service implications. The scope of charges considered in the audit exceeded $5.0 billion. Overland sampled the total population of costs through direct and statistical analysis.
- Project Director in the review of the proposed merger between Exelon Constellation Energy on behalf of the Maryland PSC. Appeared as the lead policy witness, addressing financial, governance, and rate issues implicit in the merger review. Considered the implications of market power and cost-benefit analyses in making recommendations concerning proposed settlement options.
- Project Manager in a management audit of Connecticut Natural Gas and its parent, Iberdrola USA. The audit scope included all significant functions of the company including a review of corporate governance and executive management, accounting and finance, conservation activities, and operations. A number of special topics were also addressed including: customer demand metering, billing determinates, and billing procedures.
- Project Director in the review of the proposed merger of FirstEnergy and Allegheny on behalf of the Maryland PSC. Appeared as the lead policy witness, addressing financial, governance, and rate issues implicit in the merger review. Proposed conditions necessary to comply with statutory criteria. Provided a set of ring-fencing conditions appropriate to maintain financial and governance policies necessary to protect Potomac Edison, the Maryland regulated utility under review.
- Project Director in the review of the proposed transaction between Constellation Energy and EDF involving, among other things, the sale of a 50% interest in Constellation's nuclear facilities. Lead witness on behalf of the Maryland Staff addressing various transaction issues including: impact on

Baltimore Gas & Electric customers, corporate governance and financial implications, ring-fencing measures, and cost-benefit analysis.

- Project Manager of the management audit of Atlantic City Electric and its parent PHI Holdings. The audit covered a detailed review of the corporate governance, strategic planning, executive management, and finance functions. Other key areas of review included affiliate transactions, generation and transmission planning, service quality, and system reliability.
- Project Manager in the review of long-term financial projections prepared by Midland Cogeneration Venture Limited Partnership to be used in regulatory proceedings concerning proposed modifications to a power purchase agreement. The engagement included the sensitivity testing of major variables in the partnership's financial model.
- Project Manager in the review of accounting and finance issues raised by Connecticut utilities in connection with proceedings on long-term capacity measures. Addressed the implications of new generation facilities and DSM projects on regulated electric utilities.
- Project Director for a multi-disciplinary consulting team that reviewed the proposed Exelon/PSEG merger on behalf of the New Jersey Board of Public Utilities. Also the primary expert witness in areas of finance and regulatory policy; responsible for analysis of the merger's financial impacts, in particular the impact on PSE&G, the New Jersey utility. Responsible for recommendations to insure that if the merger is approved, the transaction price, terms, and conditions are fair and reasonable in light of applicable standards for review, and that the New Jersey utility remains financially secure.
- Performed a financial and market feasibility study of a fiber optic network designed to provide SCADA requirements for a large multi-state electric utility interested in selling capacity to telecommunications carriers and high volume customers.
- Sponsored the overall development of utility revenue requirements, jurisdictional, and class cost-of-service studies and rate design issues in numerous electric, gas, water, and telecommunication cases throughout the country.
- Conducted an analysis of the adequacy of depreciation rates for a large independent telephone company located in Texas in order to assess the relationship of capital recovery in light of technological obsolescence.
- Directed and developed a two-day training seminar for the Kentucky Public Service Commission addressing energy and telecommunications issues raised in rate filings, utility planning, and forecast models required in considering the use of projected test year data.
- Supervised and directed a group of PSC Staff members in the review of a rate filing relying upon the use of a projected test year.
- Directed a comprehensive financial and regulatory base period audit of a large gas transmission and distribution company in connection with implementation of an incentive regulation plan. Reviewed savings resulting from force reductions of 1,200 employees and implementation of aggressive cost reduction programs.
- Performed a study of a LDC's gas supply and transportation procurement practices in a post-Order 636 operating environment, where the LDC's transportation and supply services continued to be provided by affiliated companies. The parent reorganized its pipeline transmission and gas supply services into a separate company, transferring jurisdiction from state regulators to the FERC. Developed a model to quantify an optimal supply and transportation mix for state ratemaking purposes.

- Performed a review of intrastate pipeline issues including the use of a straight fixed-variable cost methodology, regulatory treatment of stranded costs, pipeline competition issues, and the merits of a corporate restructuring and related effects on cost-of-service and changes in corporate operations.
- Developed a revenue requirement analysis of an intrastate gas transmission pipeline company addressing issues including: proper recognition of net operating loss carryforwards for ratemaking purposes, treatment of deferred start-up costs, application of criteria for consideration of acquisition premium in rates, and the recognition and relationship of financial criteria in the rate-setting process.
- Directed a comprehensive review of the $850 million PG&E gas transmission pipeline expansion project. This study included a review of regulatory considerations in recognizing construction and operating costs in light of competition in the California pipeline markets and, based upon the Commission intended allocation of risks among regulated customers, project shippers, and the pipeline owner.
- Directed a review of gas procurement policies and procedures and addressed the impact of FERC Order 636 for three Wyoming LDC's. This study addressed the relationship of gas pipeline and LDC affiliate organizations associated with the gas supply and transportation functions and the impact of the affiliated organizational structures on gas prices measured against other utilities in the region.
- Reviewed impacts of FERC Order 636 on gas utility distribution companies including staffing and other operating requirements, changes in gas procurement and storage policies, and effects on marketing plans. Also reviewed various pipeline compliance filings, analyzing impacts on firm and non-firm customers.
- Reviewed electric and gas utility fuel procurement policies and procedures, organization, and internal controls in various engagements. Developed recommendations resulting in significant benefits to utilities under review.
- Performed fuel audit investigations in several jurisdictions addressing such issues as economic dispatch procedures, fuel acquisition policies, affiliated mine or pipeline operations, captive mine development, and compliance with Commission rules and regulations. These studies included the review of prices and returns produced from affiliated operations versus third-party options and market prices available.
- Reviewed gas supply issues including procurement policies, supply mix, affiliate transactions, and contract provisions in the context of both cost-of-service and management review proceedings. Provided policy analysis regarding considerations and benefits of increased gas supply and pipeline competition.
- Participated in three FERC interstate pipeline rate proceedings addressing cost-of-service issues, including appropriate classification and allocation methodologies. Also addressed construction costs, overhead, and pipeline operations issues in a major oil pipeline docket.
- Performed a detailed analysis and presented testimony regarding the relative economic benefits of the operation of a LNG plant versus meeting seasonal peak demands through pipeline contract commitments.
- Developed gas transportation pricing criteria and implementation guidelines in the development of tariff service offerings for several gas LDC's.

- Developed numerous gas cost service studies and related rate design recommendations for local distribution companies, as well as pipeline suppliers. Testimony regarding such studies was presented before various state commissions, as well as the FERC.
- Responsible for gas distribution company revenue requirements in over 25 cases addressing accounting, cost allocation, operations, and rate design issues. These cases generally included an analysis of gas production, gathering, and transmission systems owned by the LDC parent.
- Developed a damages model for a gas utility in civil litigation arising from acquisition of a defective distribution system caused by improper installation practices. Measured incremental construction and operating costs associated with pipe replacement program.
- Developed a risk analysis model used to associate the relationship between cost recovery and changes in class consumption patterns for a gas distribution company.
- Developed a quantitative model to estimate jurisdictional and class-peak consumption for distribution gas companies.
- Performed an overview of regulatory considerations in the oversight of holding company formations and operations. This project was conducted on behalf of a PUC to analyze issues associated with holding company formations, utility diversification, and affiliated interest oversight and controls. The four largest electric utilities in the state were included in the study. The final report covered policy issues, as well as more detailed discussions of monitoring procedures and recommended filing requirements.
- Developed diversification guidelines for utilities in several jurisdictions. Addressed regulatory concerns and limits that might be implemented to control contingent adverse consequences to utility ratepayers.
- Performed an overview of regulatory considerations in the oversight of holding company formations and operations. This study addressed appropriate regulatory guidelines and oversight policies for utility and non-utility operations.
- Directed reviews of two major utility subsidiary gas intrastate pipeline systems, addressing cost-of-service, operating issues, and appropriate accounting for overheads and affiliated transactions from regulated electric utility parent companies.
- Developed a financing plan and reorganization of corporate structure for an electric utility having gas properties and a separate gas subsidiary. This project included preparation of SEC U-1 filings, filings with regulatory agencies, and testimony to address the impact of the proposed financing and reorganization on cost of capital and rates.
- Responsible for the independent analysis of the feasibility and economics of consolidation of two major electric utilities. The project focused primarily on the quantification of merger benefits associated with consolidated operations. This in-depth 12-month study also included a detailed review of the scope of services and basis of pricing such services among affiliates. The study addressed a number of affiliate interest issues including: the basis of pricing and level of capacity and/or energy supplied by affiliate versus third parties, the services provided by an affiliate "service" company versus internal resources or purchases from third parties, and the consideration of management resources devoted to non-utility functions and the basis of compensation for such resource transfers.
- Reviewed American Electric Power System Agreement to assess the reasonableness of fuel and purchased power costs incurred and allocated to its utility operating companies. The analysis also

considered system dispatch and related fuel accounting issues associated with energy requirements of regulated customers versus wholesale transactions.

- Responsible for the development and implementation of phase-in plans utilized to defer initial costs of new generation facilities. Developed assessment criteria and related models to assign capacity from new plant additions between jurisdictional and non-regulated service.
- Developed and conducted a training program on the measurement of relative and absolute fuel productivity measures in ranking utility's effectiveness in fuel procurement and generation system operations.
- Developed a framework for implementation of competitive pricing for an electric utility facing higher costs due to nuclear plant additions. The analysis also encompassed an incentive rate program designed to induce greater use of excess capacity, as well as to improve the utility load factor.
- Analyzed and implemented economic dispatch models used to evaluate the effects of changes in generation capacity and fuel use.
- Conducted several comprehensive nuclear management and prudence reviews addressing construction, management, planning, and economics issues.
- Directed a two-year study of the impacts on and options available to an electric utility due to the abandonment of a nuclear plant near completion. Presented a workout plan to regulators. Study involved a five-year forecast of financial results including construction expenditures and operating costs.
- Developed commercial operation date criteria and guidelines for nuclear power plants which were supported by a national industry survey.
- Developed a financial analysis of a major municipal utility facing an extended outage of its nuclear power plant, with alternative pricing strategies, recognizing competitor pricing in adjacent service areas. Developed multi-year cost-of-service and revenue requirements models and presented results to the Utility Board.
- Performed studies for municipalities to determine the feasibility of acquiring street lighting facilities or, in the alternative, pricing options other than PSC-regulated tariffs.
- Conducted an industry survey of the effectiveness and relative benefits achieved from the use of uniform filing requirements in utility rate applications. The findings were published and distributed to the utility industry and regulatory commissions.
- Developed class cost-of-service studies including identification of direct assignments and review of distribution facilities, methodologies, and criteria for the allocation of generation and bulk power facilities and risk differentials associated with various classes of service.
- Project Director of a review of Kentucky current statutes, regulations, and policies governing integrated resource planning. The project addressed recommendations necessary to mitigate impediments to the development of appropriate demand-side management programs, energy efficiency, renewables, and new generation technology options available within the state.

WATER

- Senior Auditor on two financial audits of a large Kansas City area water utility. Lead Consultant working with this client on an engagement to develop an improved model to forecast water consumption. Provided consulting services to the client in the development of inverted rate design structure.

- Project Director in revenue requirement, cost-of-service, and rate design studies for a Kansas area water utility. Responsible for the filing of two cases before the Kansas Corporation Commission. Also advised this client on the going concern valuation of the utility, relied upon in a transaction for the sale of the utility assets.
- Developed a class cost-of-service analysis involving a St. Louis area water utility and submitted the study in rate proceedings before the Missouri Public Service Commission.
- Addressed tax issues impacting the revenue requirements of a large Indiana water company before the Indiana Utility Regulatory Commission.
- Developed rate filings on behalf of several water companies within the state of Missouri. Responsible for revenue requirement, cost-of-service, and rate design evidence in two applications on behalf of this client.
- Project Manager of a regulatory audit of California American Water Company's general office activities and costs, including unregulated activities, cost allocations, and affiliate transactions.
- Project Manager in a rate design analysis of Cal Am Water Phase 2 Rate proceedings. Addressed appropriate rate design considerations in a market area highly constrained by available supply. Proposed use of inverted rates and other conservation mechanisms to address limited supply conditions. Reviewed price elasticity implications on usage, metering options for irrigation customers, cost-of-service analysis, and pricing of service charge component of customer tariffs.

VALUATION

- Conducted a feasibility study regarding the sale of a utility power plant used to provide steam heat and process steam to commercial customers through a downtown area distribution system. The feasibility study addressed energy alternatives and pricing options, cogeneration, and a financial and operating forecast assuming alternative case scenarios based upon various potential ownership structures.
- Performed a valuation analysis on behalf of an investor group for the construction and operation of a high-capacity fiber network between Seattle and Vancouver, designed to serve large commercial companies and telecommunications providers. Provided due diligence analysis of market demand and pricing assumptions, competition, and anticipated construction and operation costs.
- Performed a valuation analysis of an electric utility in the southwest on behalf of a private investor group interested in making a tender offer for the shareholder interests of this public company. Also participated in presentations to investment bankers and commercial banks who were to fund the acquisition.
- Performed a valuation study regarding two natural gas distribution affiliates in the Midwest, whose electric utility parent was seeking offers for a sale of the assets and related securities. Developed analysis of the impact of regulation on property values.
- Performed a valuation analysis of a gas transmission company used to evaluate offers for the company. Developed due diligence and information materials provided to interested parties. Participated in presentations to interested parties with investment bankers.

- Developed a valuation analysis used in litigation proceedings to support the reasonableness of the acquisition price for a rural electric company acquired by an investor-owned electric utility company.
- Developed and applied a model for the determination of the value of helium extracted from natural gas relied upon in litigation cases in federal courts in Oklahoma and Kansas. Analysis required the determination of extraction costs at plants involving four major pipeline systems in the Midwest. Developed studies of construction and operating costs associated with helium extraction plants, as well as the analysis of incremental costs and revenues related in by-product liquid extractions.
- Performed an analysis of the value of long-term gas transportation contracts relied upon in civil litigation and by regulators. The studies included the development of construction cost and operations estimates, as well as discount rates to be employed.
- Performed a reproduction cost study for a cable television company located in the west. As part of the project, developed a continuing property records system. The company used the results in the negotiation of the sale of its assets.
- Represented a member of a consortium formed to build a satellite network for cellular services with commercial applications throughout the United States. Developed a valuation analysis and business plan used in a private placement for equity financing. Acted as a co-investment advisor with a large Wall Street firm in providing these services and making presentations to potential investors.
- Developed a valuation analysis of nuclear facilities which included a detailed study of assets, and their costs, required for environmental protection as defined by state statutes and federal regulations. The study was relied upon in determining the proper classification and valuation of nuclear assets for property tax purposes.
- On behalf of a state department of revenue, developed a review of property tax rules and definitions as applied to telephone, cellular, and cable companies. The study included a national survey of valuation practices relied upon by each state department of revenue.
- Developed appraisals of telecommunications properties for property tax purposes using standard valuation methods. Presented studies in administrative and civil proceedings. Developed cost of capital analysis based upon applications of the DCF and CAPM models.
- Developed appraisals relied upon in property tax cases involving telecommunications properties where subject sales were involved within two years of the date of property assessment.
- Prepared appraisals for a natural gas transmission company in appeals of property tax assessments in administrative proceedings in Kansas and Oklahoma.
- Prepared appraisals of two investor-owned utilities on behalf of the Iowa Department of Revenue. The appraisals included a subject sale analysis and a review of economic obsolescence.
- Developed appraisals of two Class I railroad companies in contested property tax valuation in civil proceedings in New York. Valuation studies included the review of the cost method based on RCNLD.
- Assisted an electric G&T coop in valuation and due diligence analysis of electric and gas properties offered for sale by a large independent telephone company.
- Developed a manual for "Alternative Valuation Procedures" on behalf of the Virginia State Corporation Commission – Public Service Taxation Division in a state that otherwise relies on the cost method.

- Developed a business plan and other financial advisory services to the National Homebuilders Association joint venture subsidiary, "Smarthouse," in connection with securities offerings.
- Developed a complete appraisal of a cogeneration facility on behalf of the Virginia State Corporation Commission – Public Service Taxation Division. The study included "Subject Sale" and "Comparable Company" analyses, as well as a review of capacity and energy forecast prices in the PJM market area.
- Prepared a complete appraisal of CSX Railroad operating property on behalf of the Florida Department of Revenue.
- Prepared a complete appraisal of Qwest Corporation on behalf of the Iowa Department of Revenue. The appraisals included "Subject Sale" and "Comparable Company" market analyses.
- Developed a complete appraisal of the Dickerson Electric Generation Plant located in Dickerson, Maryland, on behalf of the Maryland State Department of Assessments and Taxation and Montgomery County, Maryland. The plant was comprised of three coal and three gas units with a total capacity of approximately 900 Mw. The ultimate owner of these facilities was Mirant Corporation, now known as GenOn Energy.
- Retained by the Virginia Public Service Taxation Division to perform a valuation of the Portsmouth Genco and James River Genco, both coal-fired generation units. The units were owned and operated by Cogentrix Energy, whose ultimate owner was the Carlyle Group.

TELECOMMUNICATIONS

- Developed and directed a three-day nationally attended conference entitled, "Competitive Strategies in the Local Exchange Marketplace."
- Directed audits of RBOCs regarding compliance with regulatory accounting requirements, procedures to allocate costs between regulated and non-regulated activities, policies and rules for pricing transactions among affiliates, and monitoring reports filed with regulators.
- Conducted a review of depreciation rates for local exchange telecommunications property of the central division of a national carrier.
- Directed a comprehensive review of the operation of a RBOC telecommunications incentive plan, based upon a revenue sharing mechanism, over a three-year period. The study reviewed quality of service measures, capital expansion programs, workforce reductions, and other major elements of operating expense for the review period. Provided policy options regarding modifications to the incentive plan for prospective consideration.
- Developed a business plan and other related materials for a telecommunications reseller in its initial public offering. Provided ongoing financial and regulatory services, including development of all SEC filings.
- Directed an analysis of switching and other LEC facilities required and costs of providing inter-exchange services to an alternative service provider in the Phoenix, AZ, area.

INCOME TAX

- Expert witness in numerous regulatory proceedings addressing the proper recognition of investment tax credits and accelerated depreciation for accounting and ratemaking purposes. Provided guidance on intent of IRS regulations in use of tax benefits in the rate-setting process. Such testimony was provided in a number of jurisdictions including: Arizona, Oklahoma, Missouri, Indiana, Kansas, and Mississippi.

- Addressed the implications of utility net operating loss carryforwards for GAAP and ratemaking purposes before the Kansas Corporation Commission and the FERC.
- Provided expert analysis and testimony on the proper recognition of tax benefits arising from participation of subsidiary utilities in consolidated tax returns that include regulated and unregulated affiliates.
- Expert witness testimony and analysis of tax timing differences arising from utility operations as considered for income tax, accounting, and ratemaking purposes. Provided an assessment of proper application of normalization or flow-through of tax timing differences for accounting and ratemaking purposes. These issues were addressed in over 20 cases in various jurisdictions throughout the U.S.

Education and Professional Certification

- **University of Missouri – Kansas City,** Kansas City, MO
  Bachelor of Business Administration – Accounting, Economics Minor, May 1968.
- **University of Missouri – Kansas City,** Kansas City, MO
  Graduate studies in quantitative and systems analysis, 1968 – 1970.

Publications and Presentations

- *Utility Merger Review – Training Workshop for Regulators and Consumer Stakeholder Representatives.* An advanced course discussion of utility M&A technical and policy issues. Presented to Regulators and Staff in Dover, DE, and Trenton, NJ, May 2015.
- *Systematic Ring Fencing: A Quantitative Approach to Balancing the Interests of Utilities and Regulation.* Presented at the NARUC Accounting & Finance Spring Meeting, Jacksonville, FL, March 2014.
- *CPUC Knowledge Transfer Workshop – Executive Summary.* A presentation for senior staff and policy makers, February 2014.
- *California Public Utilities Commission Staff Workshop.* An overview of management, financial, and regulatory considerations associated with the PG&E San Bruno incident, November 2013.
- *How to Build a Fence (and When);* Ryan Pfaff and Leslie Romine, co-authors. *Public Utilities Fortnightly,* October 2013.
- *Constellation/EDF Nuclear Joint Venture: Regulatory Issues and Subsequent Resolutions.* Ryan Pfaff, co-author. Published in the *Electricity Journal*, March 2010. Also presented at the Western States Association of Tax Administrators Annual Meeting, February 2010.
- *Rating Agencies – Current Methods Employed and Recognition of Imputed Debt.* WSATA Unitary Appraisal School, Advanced Class, Logan, UT, January 2008.
- *Accounting Pronouncements Impacting Financial Reporting Associated with Utility Purchase Power Agreements.* WSATA Unitary Appraisal School, Advanced Class, Logan, UT, January 2008.
- *Accounting and Finance Issues Associated with Contracts for Differences – Generation/DSM Projects.* Gregory Oetting, co-presenter. Connecticut Department of Public Utility Control, September 2007.
- *Overview of FIN 46(R), SFAS No.* 133, and SFAS No. 71. Gregory Oetting, co-presenter. Connecticut Department of Public Utility Control, May 2007.

- *The Yield Capitalization Method – Application Issues.* WSATA Unitary Appraisal School, Advanced Class, Logan, UT, January 2007.
- *Blue Chip Method Overview.* 21st Conference of Unit Value States, Memphis, TN, October 2004.
- *Appraisers Find Help in Recent Accounting Rules.* Gregory Oetting, co-author. *Fair & Equitable,* August 2003.
- *Impact of Deregulation and Competition On Property Tax Valuation Within the Utility Industry.* Western States Association of Tax Administrators, Austin, TX, September 1995.
- *Considerations Associated with the Review of Rate Applications Based Upon Projected Test Periods.* A two-day training seminar conducted on behalf of the Kentucky Public Service Commission, December 1992.
- *Competitive Strategies in the Local Exchange Marketplace.* A three-day telecommunications conference sponsored by Overland Consulting and the University of Missouri – Kansas City, September 1991.
- *Framework for a Competitive Strategy.* Southeastern Regional Public Utilities Conference, Atlanta, GA, September 1988.
- *Regulatory Considerations Inherent in Assessing Utility Culpability.* Richard Ganulin, co-author. *Public Utilities Fortnightly,* 1987.
- *On the South Texas Project and Other Cases.* Published in *The Advisory,* March 1987.
- *Regulatory Implications Associated with the Prudence Audit Process.* NARUC Biennial Regulatory Information Conference, September 1986.
- *Review of The Proposed Amendment to FASB Statement No. 71.* Presentation to the Financial Accounting Standards Board, June 1986.
- *Rate Moderation Plan Considerations.* Presented at the Public Utilities Accounting and Ratemaking Conference, sponsored by the Texas Society of CPAs, April 1985.
- *Regulatory and Accounting Implications of Phase-in Plans.* Presented at the NARUC Biennial Regulatory Information Conference with Gary Harpster, co-presenter, September 1984.
- *The Use of Uniform Filing Requirements by State Regulatory Commissions – An Industry Survey.* May 1980.

Gregory S. Oetting, CPA, Director

Overland Consulting | 11551 Ash Street, Suite 215 | Leawood, KS 66211 | 913-599-3323
goetting@overlandconsulting.com

General

Regulatory consultant to the electric, gas, water, and telecommunications industries, Mr. Oetting has experience in financial and regulatory reviews, management audits, and valuations. His regulatory and management audit experience includes reviews of cost allocation methodologies, compliance with competitive service standards, and internal controls. Mr. Oetting has also been involved in the valuation of several utilities and railroads in which industry cost of capital was analyzed. Mr. Oetting has over 20 years of regulated industries consulting experience, three years of experience as an auditor in a national CPA firm, and three years of experience as a controller of an interstate natural gas pipeline.

Professional Work History

Overland Consulting *2000 – Present*
Director

Direct energy and telecommunications industry consulting projects on behalf of public utilities commissions, other government agencies, and industry participants.

Midcoast Energy Resources, Inc., Kansas Pipeline Operating Company *1997 – 2000*
Controller

Supervised the accounting and cash management functions of an interstate natural gas pipeline company.

Overland Consulting *1995 – 1997*
Senior Consultant

Participated in energy and telecommunications industry consulting projects on behalf of companies, public utilities commissions, and other government agencies.

Various *1990 – 1995*

Served as special projects accountant and supervisor of accounting for various companies in private industry.

Arthur Andersen & Company *1987 – 1990*
Senior Accountant

Planned, supervised, administered, and reported on audits and other engagements in a variety of industries including utilities. Experienced in the evaluation of internal controls.

Professional Experience

Electric, Gas, Water, and Telecommunications

- Lead Consultant in a review of Public Service Electric & Gas Company's base rate case filing on behalf of the New Jersey Board of Public Utilities. Responsible for reviewing the company's incentive compensation proposal as well as other revenue requirement issues. *2018*

- Lead Consultant in a comprehensive management audit of New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation, on behalf of the New York State PSC. Responsible for analyzing the utilities' performance management, budgeting, and procurement activities. Also reviewed the implications of the utilities' recent IT system conversion. *2017 – Present.*
- Lead Consultant in a comprehensive management and operations audit of Central Hudson, on behalf of the New York State PSC. Responsible for analyzing the utility's performance management activities as well as those related to project and work management. *2016 – 2017.*
- Lead Consultant in a focused review of the general rate application of Southwest Gas Corporation, on behalf of the Arizona Corporation Commission. Responsible for a review of gas procurement. *2016 – 2017.*
- Lead Consultant in the evaluation of the acquisition of Pepco Holdings, Inc., by Exelon Corporation. This work was performed for the Staff of the Maryland Public Service Commission. Analyzed merger accounting and tax matters associated with the transaction. *2014 – 2015.*
- Technical Manager in a focused audit of all major electric and gas utilities in the state of New York. Responsible for analyzing the reliability and comparability of gas safety performance metrics reported to the New York Public Service Commission. *2014 – 2015.*
- Technical Manager in the focused audit of PG&E capital and operations expenditures related to the company's gas distribution system. This work was performed for the California Public Utilities Commission. *2012 – 2013.*
- Technical Manager in the management audit of South Jersey Gas Company for the New Jersey Board of Public Utilities. Responsible for analyzing executive management and corporate governance matters. *2012 – 2013.*
- Technical Manager in the investigation of National Grid affiliate cost allocations, policies, and procedures. This work was performed for the New York Public Service Commission. *2011 – 2012.*
- Technical Manager in the review of the proposed merger between Constellation Energy Group and Exelon Corporation. This work was performed for the Staff of the Maryland Public Service Commission. Provided testimony on several subject matters, including the treatment of transaction costs related to the merger, financial and operational profiles of the applicants, and taxes. *2011.*
- Lead Consultant in the evaluation of the acquisition of Allegheny Energy Inc. by FirstEnergy Corp. This work was done for the Staff of the Maryland Public Service Commission. Analyzed merger accounting and tax matters associated with the transaction as well as certain other areas relevant to the public interest criteria. *2010.*
- Technical Manager in the management audit of Public Service Electric & Gas Company for the New Jersey Board of Public Utilities. Responsible for analyzing executive management and corporate governance matters, customer service, accounting, cash management, and finance. *2009 – 2011.*
- Technical Manager in the diagnostic management audit of Connecticut Natural Gas Corporation for the Connecticut Department of Public Utility Control. Areas of responsibility included finance, accounting and internal controls, executive compensation, system design, planning, and construction. *2009 – 2010.*

- Lead Consultant in the review of the impact on Baltimore Gas and Electric Company of the proposed transaction of its parent, Constellation Energy Group, with EDF. This transaction involved the sale of a 50% interest in Constellation's nuclear facilities. This work was performed on behalf of the Staff of the Maryland Public Service Commission. Provided testimony on subject matters relevant to the public interest criteria, including costs associated with the transaction, credit ratings, cost of capital, and liquidity. *2009.*
- Technical Manager in the management audit of Atlantic City Electric Company for the New Jersey Board of Public Utilities. Analyzed various matters including accounting and property records, cash management, financing, customer service, and support services. *2008 – 2009.*
- Participated in the regulatory audit of California American Water Company's general office activities and costs, including unregulated activities, cost allocations, and affiliate transactions. *2008.*
- Participated in the review of long-term financial projections prepared by Midland Cogeneration Venture Limited Partnership to be used in regulatory proceedings concerning proposed modifications to a power purchase agreement. The engagement included the sensitivity testing of major variables in the partnership's financial model. *2008.*
- Participated in the review of Kentucky current statutes, regulations, and policies governing integrated resource planning. The project addressed recommendations necessary to mitigate impediments to the development of appropriate demand-side management programs, energy efficiency, renewables, and new generation technology options available within the state. *2008.*
- Technical Manager in the review of the General Rate Case Applications of San Diego Gas & Electric Company and Southern California Gas Company on behalf of the Utility Consumers' Action Network. Analyzed the shared utility services of both companies. *2007.*
- Technical Manager in the review of accounting issues raised by Connecticut utilities in connection with proceedings on long-term capacity measures. *2007.*
- Technical Manager in the regulatory audit of Verizon California. Analyzed the financial reporting of the Company in accordance with California Public Utilities Commission rules and requirements. *2006 – 2007.*
- Technical Manager in the review of the Public Service Enterprise Group/Exelon Corporation merger petition on behalf of the New Jersey Board of Public Utilities. Analyzed the financial impacts of the merger, in particular the proposed money pool arrangement between affiliates. *2005 – 2006.*
- Technical Manager in the regulatory audit of South Jersey Gas Company. Analyzed the allocation of costs between South Jersey Gas Company and affiliates and compliance with competitive service standards of the New Jersey Board of Public Utilities. *2002 – 2003.*
- Technical Manager in the regulatory audit of Pacific Bell. Analyzed the allocation of costs from affiliates to Pacific Bell in accordance with California Public Utilities Commission rules and requirements. *2001 – 2002.*
- Controller of a Midwest-based interstate pipeline. Responsible for all financial reporting ranging from monthly to annual financial statements and detailed regulatory reports filed with pipeline regulatory bodies. Position involved extensive analysis and evaluation of all financial transactions as well as supervision of accounting department staff. Assisted in the preparation of a rate case filing before the Federal Energy Regulatory Commission. Assisted in valuations related to the potential purchase or sale of utility assets. *1997 – 2000.*

- Participated in the focused management audit of Harrison County Rural Electric Cooperative Corporation. *1997.*
- Participated in Overland's audit of the Southern California Gas Company's performance based management (PBR) incentive rate plan application. *1995 – 1996.*
- Participated in the determination of gas pipeline utility cost of service in Overland's rate case audit of the Kansas Pipeline Operating Company. *1995.*
- Participated in the planning, administration, and financial reporting of the first-time-through audit related to United Cities Gas Company's acquisition of Union Gas Company. *1990.*
- Participated in the audit of St. Joseph Light & Power Company for three years. Responsibilities included the planning, supervision, and reporting of numerous engagements (10Q and 10K). *1987 – 1990.*
- Participated in the audit of Raytown Water Company for three years. Responsibilities included the planning, supervision, and financial reporting of the annual audit. *1987 – 1990.*

VALUATION

- Technical Manager for an independent valuation of the Wheelabrator Portsmouth waste-to-energy facility. This valuation is being developed for use in a property tax appeal proceeding in the Commonwealth of Virginia. *2018*
- Technical Manager for an independent valuation of the Dickerson Plant located in Montgomery County, MD. This valuation was developed for use in a property tax appeal proceeding in the State of Maryland. *2013 – 2014.*
- Technical Manager for an independent valuation of the telecommunications personal property of Verizon Virginia and Verizon South. This valuation was developed for use in a property tax appeal proceeding in the Commonwealth of Virginia. *2010 – 2011.*
- Technical Manager for an independent valuation of the operating property of Qwest Corporation. This valuation was used in settlement negotiations related to a property tax appeal in the State of Iowa. *2006.*
- Technical Manager in the development of alternative valuation procedures under consideration for use in utility assessments in Virginia. *2005.*
- Technical Manager for an independent appraisal of the Hopewell Cogeneration Facility. This valuation was used in a property tax appeal in the Commonwealth of Virginia. *2004 – 2005.*
- Technical Manager for an independent appraisal of CSX Corporation's railroad operating property. This valuation was utilized in settlement negotiations related to a property tax appeal in the State of Florida. *2004.*
- Technical Manager for an independent utility valuation of Interstate Power Company's operating property. This valuation was utilized in settlement negotiations concerning a property tax appeal before the Iowa State Board of Tax Review. The valuation included a subject sale analysis as well as other generally recognized valuation approaches. *2002 – 2003.*
- Assisted in the development of appraisals of two Class I railroad companies in contested property tax proceedings in New York. *2002.*
- Performed a utility valuation appraisal relied upon in determining the market value of Citizens Utilities Company's Arizona Telephone Operations for property tax purposes. The appraisal

incorporated applications of the stock and debt method, direct and yield capitalization methods, and analysis of market transactions. *1995.*

Education and Professional Certification

- **University of Kansas,** Lawrence, KS
  Bachelor of Science – Accounting and Business Administration, May 1987.
- Certified Public Accountant Certificates in Kansas and Missouri
- Kansas CPA Certificate #1718

Professional Affiliations

- The American Institute of Certified Public Accountants

Publications and Presentations

- *California Public Utilities Commission Staff Workshop.* An overview of management, financial, and regulatory considerations associated with the PG&E San Bruno incident, November 2013.
- *Accounting and Finance Issues Associated with Contracts for Differences – Generation/DSM Projects.* Howard Lubow, co-presenter. Connecticut Department of Public Utility Control, September 2007.
- *Overview of FIN 46(R), SFAS No.* 133, and SFAS No. 71. Howard Lubow, co-presenter. Connecticut Department of Public Utility Control, May 2007.
- *Appraisers Find Help in Recent Accounting Rules.* Howard Lubow, co-author. *Fair & Equitable,* August 2003.

Robert F. Welchlin, Director

Overland Consulting | 11551 Ash Street, Suite 215 | Leawood, KS 66211 | 913-599-3323
rwelchlin@overlandconsulting.com

General

Regulatory consultant to the telecommunications, cable, electric, and gas industries. Mr. Welchlin manages operational, financial and regulatory audits, reviews of rate filings and cost studies in the energy utility, telecommunications, and cable industries. He has 35 years of regulated industries experience.

Professional Work History

Overland Consulting *1996 – Present*
Director

Plan, supervise, and perform telecommunications and energy industry consulting projects, including audits, on behalf of public utility commissions and other government agencies.

KPMG Peat Marwick LLP *1993 – 1996*
Senior Manager

Information, communications, and entertainment lines of business. Developed and managed cable TV and telecommunications and industry consulting engagements.

LMSL, Inc. *1987 – 1993*
Manager

Conducted audits of energy and telecommunications companies and sponsored testimony in regulatory proceedings. (LMSL is a predecessor firm of Overland Consulting.)

Public Utility Commission of Texas *1984 – 1986*
Senior Staff Accountant

Reviewed electric, telephone, and water utility rate and regulatory filings and sponsored cost-of-service testimony in rate hearings.

Illinois Power Company *1980 – 1983*
Senior Internal Auditor

Planned, directed, and performed operational and financial audits of the company's headquarters departments, power stations, and service offices. Prepared the annual department operating plan and drafted the report to the Audit Committee of the Board of Directors for approval by the Director of Internal Auditing. Coordinated work with external auditors.

Professional Experience

Electric and Gas

- Technical Manager in a management audit of affiliate transactions and cost allocations of Avangrid's Inc's New York utilities, New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E). Analyzed compliance with New York's Affiliate Standards for both utilities. Reviewed corporate cost allocations from the utilities' global parent (Iberdrola) through Avangrid to the utilities and from Avangrid's service companies to the utilities, including the distribution of costs among Iberdrola's country-based companies (to Avangrid) and between Avangrid's regulated utility and unregulated (renewable energy) business segments. Also served as Technical Manager in a management review of NYSEG's and RG&E's customer service operations and a review of the utilities' compliance with New York state customer service rules (the Home Energy Fair Practices Act, or HEFPA) *2017 and 2018*

- Technical Manager in review of the impact of AltaGas Ltd's (Alberta, Canada) proposed acquisition of WGL Holdings, Inc. (WGL). Responsible for review of the potential impact of proposed acquisition accounting, income tax issues, merger transaction and transition costs and AltaGas-proposed allocations of its corporate costs to WGL's utility, Washington Gas Light (Wash. D.C.). Responsible for analysis of the potential for realizing synergy savings as asserted by the Applicants and the likely impact of accounting, corporate cost allocations, merger costs and savings on the Washington Gas customers. Submitted testimony and participated in the merger hearing before the Maryland Public Service Commission. The work was performed for the Staff of the Maryland PSC. *2017*

- Technical Manager in a management audit of Central Hudson Gas & Electric performed on behalf of the New York Department of Public Service. Managed the audit component that included the Customer Service function and the Company's compliance with the Home Energy Fair Practices Act and related rules for commercial customers. *2016 - 2017.*

- Project Manager for an analysis of the Wexpro I and II agreements and an audit of expenses charged to Questar Gas for 2005 to 2014. The audit included an in-depth review of costing procedures attributed to the Operator Service Fee and recognition of capital additions considered under the agreements. This engagement was performed for the Utah Division of Public Utilities. *2015 – 2017*

- Lead Consultant in the evaluation of the acquisition of Pepco Holdings, Inc., by Exelon Corporation. Conducted a detailed review of Exelon's merger savings and merger costs to achieve on behalf of the Staffs of the Maryland and Delaware Public Service Commissions. Developed testimony on behalf of the Public Service Commission Staff in each state concerning the net savings attributable to Maryland and Delaware. *2014 – 2015.*

- Project Manager in a focused audit of the data supporting operational metrics submitted to the New York Department of Public Service by all nine large investor-owned electric and gas utilities in the state of New York in the areas of gas safety, electric reliability and customer service. Technical Manager in charge of the audit of the audits of customer service metrics for nine utilities. Audit objectives included determination of the accuracy, completeness, and comparability of data submitted by the utilities to the NYSDPS. *2014 – 2015.*

- Project Technical Manager in a regulatory and management audit of the affiliate transactions, management, and operations of South Jersey Gas Company. Responsible for accounting procedures and costs charged to the regulated gas company from the parent and service companies, transactions with affiliate South Jersey Energy Solutions and its subsidiaries, and operational and management reviews of various support services (supply chain, fleet management, facilities management), customer service operations, construction contractor management, and excavation damage prevention. *2012 – 2013.*

- Project Manager in the investigation of National Grid affiliate cost allocations, policies, and procedures. The audit included a review of accounting procedures and internals governing service company transactions, an analysis of service company cost allocation procedures, and a regulatory audit of the costs charged by the service companies to National Grid's New York distribution utilities (Niagara Mohawk, KeySpan Energy Delivery New York, and KeySpan Energy Delivery Long Island, Massachusetts Electric, Boston Gas and others). It also included a detailed analysis of sampled and targeted transactions between the service companies and the New York utilities over a 20-month period. The work was performed for the New York Public Service Commission. *2011 – 2012.*

- Project Lead in charge of the evaluation of the acquisition of Allegheny Energy Inc. by FirstEnergy Corp., including the merger synergies and likely impacts of the merger on Potomac Electric Maryland service company cost distributions. This work was done for the Staff of the Maryland Public Service Commission. Calculated discounted cash flow value of net regulated synergies attributable to Potomac Maryland customers. Recommended post-merger review of the impact of allocation procedures on regulated Maryland utility operations. *2010.*
- Technical Manager in the diagnostic management audit of Connecticut Natural Gas Corporation for the Connecticut Department of Public Utility Control. Areas of responsibility included transactions with and services exchanged with Southern Connecticut Gas, Energy East, and other affiliates, human resources (staffing, compensation, labor relations, and performance appraisal processes), customer service and call center operations, dispatch, field operations and appliance services, meter operations, distribution sales and marketing, supply chain management, fleet operations, facilities management, security and external relations. *2009 – 2010.*
- Lead Consultant in the review and preparation of testimony concerning the potential impact of the proposed Constellation Energy Group/Électricité de France Nuclear Power Joint Venture. *2009.*
- Technical Manager in the management audit of Atlantic City Electric Company for the New Jersey Board of Public Utilities. Areas of responsibility included allocations of corporate and shared utility costs, transactions with affiliates, compliance with New Jersey's Electric Discount and Energy Competition Act (EDECA), and the management of various functions, including information technology, fleet, stores and supply chain, security, facilities, real estate, and records management. *2008 – 2009.*
- Assisted the New Jersey Board of Public Utilities in review of the proposed merger of Exelon (Commonwealth Edison, Pennsylvania Energy) with PSEG (Public Service Electric & Gas). Responsible for the review of the impact of combining the two holding companies' service companies (the companies that provide managerial, technical, and administrative services to associated companies) on the New Jersey Genco and utility. *2005 – 2006.*
- Project Manager for a review of the costs of Sempra Energy's holding company. The review, conducted on behalf of the Utility Consumer Action Network (UCAN), was a part of the review of Sempra Energy's rate application with the California Public Utilities Commission (A.02-12-027 and A.02-12-028). Performed a similar review in the subsequent rate applications of subsidiaries, San Diego Gas & Electric Company and Southern California Gas Company (A.06-12-009 and A.06-12-010). *2003 and 2007, respectively.*
- Project Manager for audits of the affiliate relationships and cost allocations of Elizabethtown Gas, New Jersey Natural Gas, and South Jersey Gas conducted on behalf of the New Jersey Board of Public Utilities (BPU). The audits examined whether each Company maintained a strict separation of risks, functions, and assets between their regulated utilities and unregulated affiliates to comply with BPU Standards. The audits also documented each Company's cost allocation methodologies and results for a two-year period. *2002 – 2003.*

- Directed the cost of service component of the initial FERC "Section 7" cost-of-service and base rate filing of Kansas Pipeline Company, which had been exempt from FERC rate regulation prior to 1997. Submitted and defended testimony on behalf of Kansas Pipeline before the FERC covering the overall cost of service filing, the historical basis for the calculation of acquisition premium, and company's test year operations and maintenance expenses. *1998 – 2000.*
- Working on the Pacific Gas and Electric 1999 General Rate Case, reviewed projected test year administrative and general expense levels and allocation of costs between the utility and affiliates. Submitted and defended testimony on behalf of the California Public Utilities Commission. *1998.*
- Managed an audit of Pacific Gas and Electric's compliance with regulatory requirements and internal control over relationships and transactions between the utility and its unregulated affiliates on behalf of the California Public Utilities Commission. *1998.*
- Conducted a review of Southern California Gas Company's 1994 and 1995 base margin costs. Submitted testimony on behalf of the California Public Utilities Commission. Issue areas included operations and maintenance expenses, corporate allocations, employee and executive compensation, post-retirement benefits, and savings from restructuring and force reduction programs. *1996.*
- Submitted cost of service testimony on behalf of Mid-Kansas Partnership and Riverside Pipeline, L.P., in connection with Missouri Gas Energy's base rate filing. Issues included deferred gas safety costs, merger-related savings, and weather normalization. *1996.*
- Reviewed fuel receiving and inventory policies and coal contract terms in connection with a focused management audit of Big Rivers Electric Cooperative's fuel procurement for the Kentucky PSC. *1993.*
- Participated in the Western Resources/Kansas Power and Light Rate Case by conducting a rate case audit and submitting and defending cost-of-service testimony on jurisdictional cost allocations, operations and maintenance expenses, and pension expenses on behalf of the Kansas Corporation Commission. *1992.*
- Conducted focused management audits of the gas supply operations of Montana Dakota Utilities and Mountain Fuels for the Wyoming PSC. Assessed the management and organization of each company as it related to gas supply, the degree to which supply options were optimized, the potential impact of FERC Order 636, and the relationships between the LDCs and their pipeline and production affiliates. *1992.*
- Performed internal operational audits of nuclear and fossil fuel procurement, natural gas procurement and delivery, various corporate, power plant and service area operations, and nuclear plant construction contracts of the Illinois Power Company (Illinova). *1980 – 1983.*

TELECOMMUNICATIONS

- Directed a California statutory regulatory audit of Citizens' California PUC financial reporting and shareable earnings, including transactions between Citizens, its Connecticut-based parent company, and its affiliates as part of the Frontier (Citizens) Telecommunications Regulatory Audit. *2004 – 2005.*
- As a participant in the Roseville Telephone Regulatory Audit, directed and conducted a regulatory audit of the company's compliance with affiliate and non-regulated activity transaction rules and reviewed the company's calculation of earnings shareable with customers under the California

PUC's New Regulatory Framework rules. Submitted and defended testimony on the audit on behalf of the CPUC. *1999 – 2000.* Performed a follow-up audit of 2001 – 2003 regulated earnings. *2004.*

- Directed a California statutory regulatory audit of Pacific Bell's California PUC financial reporting, including transactions between Pacific Bell, its parent company (SBC), and its affiliates and subsidiaries. *2001 – 2002.*
- Directed a study of New York Telephone's subscriber loop network. Coordinated the effort of a multi-disciplined team that included regulatory, network operations, engineering, and data processing specialists. The major work products included an inventory of subscriber facilities, determination of facility utilization in different geographic regions, determination of the relative accuracy of the major databases containing network facility information, and verification of billing records with installed facilities. *1991.*
- Conducted a review of the affiliate management and accounting relationships among the subsidiaries of AT&T. Documented significant transactions and allocations through the AT&T organization that affected AT&T Communications. Examined policies and procedures that affected the Communication subsidiary's decision to use internal sources of supply and the corporate entity's allocation of costs to subsidiaries. *1990.*
- Analyzed the GTE Corporation's Indiana local exchange rates and developed a computer model to distribute the carrier's revenue requirement over a matrix of local services and rate groups. *1989.*
- Bay Area Teleport – Conducted a review of the impact of local exchange carrier price flexibility on competitive access in California. *1988.*

WATER

- Twice Technical Manager for the regulatory audit of California American Water Company's general office activities and costs, including "California Corporation" administrative and general activities, New Jersey service company activities and cost allocations, and related ratemaking issues. Submitted revenue requirements testimony covering CalAm's projected test years covering the O&M expenses of functions allocated from the national, regional, and state levels to the district operations for which CalAm was seeking an increase in rates. *2008 – 2013.*
- Performed revenue requirements reviews and filed related testimony relating to rate filings by several water utilities in Texas while an employee of the Accounting Division of the Texas Public Utilities Commission *1984-1986*

CABLE

- Analyzed costs imposed on cable systems by late-paying customers and prepared studies to quantify the additional costs of handling past due accounts. *1995 – 2001.*
- Analyzed cable system costs and prepared cost-of-service rate studies for cable companies, including two of the nation's largest cable systems – TCI Chicago and DCLP. Developed cost-of-service methodologies to properly account for affiliate relationships and corporate and divisional cost allocations to the cable systems. Analyzed incremental cost of service under FCC Form 1235 rules for a group of systems calculating the revenue requirement impact of upgrading system capacity upgrades. *1994 – 1995.*
- Developed a database application to calculate programming cost increases on a cable-system basis to comply with FCC requirements. *1994.*

EDUCATION AND PROFESSIONAL CERTIFICATION

- **Eastern Illinois University,** Charleston, IL
  Bachelor of Science – Accounting and Business Administration, August 1979.
- **St. Edwards University,** Austin, TX
  Master of Business Administration, May 1986

- American Institute of Certified Public Accountants

Arizona Public Service Company
Docket No. E-01345A-19-0003

On this 4th day of June, 2019, the foregoing document was filed with Docket Control as a Utilities Division Notice of Filing - Miscellaneous, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

Robin Mitchell
Director/Chief Counsel, Legal Division
Arizona Corporation Commission
Utilities Division
1200 West Washington Street
Phoenix, Arizona 85007
legaldiv@azcc.gov
utildivservicebyemail@azcc.gov
Consented to Service by Email

Stacey Champion
3101 North Central Avenue, Suite 174
Phoenix, Arizona 85012
sc@champion-pr.com
Consented to Service by Email

Thomas Loquvam
Pinnacle West Capital Corporation
Arizona Public Service Company
400 North 5th Street, Mail Stop 8695
Phoenix, Arizona 85004
thomas.loquvam@pinnaclewest.com
Melissa.Krueger@pinnaclewest.com
Kerri.Carnes@aps.com
Debra.Orr@aps.com
Thomas.Mumaw@pinnaclewest.com
Theresa.Dwyer@pinnaclewest.com
Consented to Service by Email

By: ______________________
Edna Luna-Reza
Administrative Support Specialist